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Revision 0

GETEM User Manual

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July 2016

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Approved by:

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Date

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SUMMARY

This report provides information for using and understanding the Geothermal Electricity Technology Evaluation Model (GETEM). GETEM estimates the representative costs associated with generating electrical power from geothermal energy. These projected costs are based upon a number of factors specific to each scenario evaluated; most of these factors are defined by inputs provided. The projected costs and annual power sales can be used to interpret a levelized cost of electricity (LCOE).

The purpose behind GETEM's development is to allow the U.S. Department of Energy's Geothermal Technologies Office (GTO) to comply with the Government Performance and Results Act of 1993 (GPRA). GETEM allows GTO to annually assess, quantify, and report the impact of improvements that have occurred with geothermal power generation. In addition, identifying the different contributors to the cost of electricity generated from geothermal energy contributes to GTO understanding of how technology improvements affect generation costs. This assists GTO in developing a research portfolio that provides an optimal return on the investment of taxpayer dollars in its research program. With these goals in mind, INL developed the GETEM model as a series of iterations from 2004 through 2013.

The GETEM User Manual provides a comprehensive overview of this Excel-based model, how to use it, its limitations, and how to interpret the results. It designates the factors that can be inputted manually, as well as those that are automated or fixed. The manual lists and describes available worksheets, their purposes, and how to use them. With the information given, a user can define each facet of a scenario for geothermal energy production, produce useful information for estimating costs, and correctly interpret the results.

Appendices A1–A15 provide more detailed information on aspects of determining power generation costs. These appendices define parameters for scheduling, well count, drilling, and other relevant considerations. They provide sources for pertinent information, such as the U.S. Bureau of Labor Statistics Producer Price Index. They also lay out the mathematical formulas used in the model. Appendix A-14 lists possible errors and warnings that can appear when problematic input is provided, along with helpful explanations of how to resolve them. Appendix A-15 provides information on how to activate the Excel add-ins that are needed to run the program.

Appendices B1 and B2 address resource productivity. They provide valuable information that helps the user understand production issues inherent to geothermal energy production, as well as how they apply to creating estimations in GETEM.

If the instructions in this manual and understood and followed, GETEM can be a highly useful tool for planning and analyzing geothermal energy plants.

ACKNOWLEDGMENT

In developing GETEM, multiple individuals from the geothermal industry have provided invaluable input for all phases of the development of a geothermal project. Hopefully the model, as currently configured, adequately depicts that input.

The individuals who have directly contributed to developing the model include:

Dan Entingh, Princeton Energy Resources International
Gerry Nix and Chad Augustine, National Renewable Energy Laboratory
Chip Mansure and John Finger, Sandia National Laboratory
Susan Petty, Altarock/Black Mountain Technology
Marty Plum, Idaho National Laboratory
Mark Paster, Consultant
Ella Thodal and Steven Hanson, SRA International
Erin Camp, Sentech, Inc.
Christopher Richard, BCS, Inc.
Ma Seungwook, DOE-EERE Strategic Analysis Group
Jay Nathwani, DOE-GTO

In addition, the following Idaho National Laboratory interns have worked to utilize the data reported to the NV DoM to improve GETEM's characterization of reservoir performance.

Hillary Hanson, University of Idaho
Rachel Wood, Washington State University
Hannah Wright, Colorado State University
Dylan Glenn, Century High School, Pocatello ID

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ACRONYMS

BLM	Bureau of Land Management
COE	cost of electricity
DCF	discounted cash flow
DOE	Department of Energy
DSR	drilling success rate
EERE	Office of Energy Efficiency and Renewable Energy
EIA NEMS	Energy Information Administration National Energy Modeling System
EPRI	Electric Power Research Institute
ESMAP	Energy Sector Management Assistance Program (World Bank)
FCR	fixed charge rate
GETEM	Geothermal Electricity Technology Evaluation Model
GPRA	Government Progress and Results Act
GRC	Geothermal Resources Council
GTO	U.S. Department of Energy's Geothermal Technologies Office
II	Injectivity Index
IPE	Icarus Process Evaluator
LCOE	levelized cost of electricity
LMTD	log mean temperature difference
MACRS	modified accelerated cost recovery
MCCA	major component cost adjustment
NCF	net capacity factor
NCG	non-condensable gas
NIST	National Institute of Standards of Technology
NV DoM	Nevada Division of Minerals
NOAA	National Oceanic and Atmospheric Administration
O&G	oil and gas
O&M	operations and maintenance
PI	Productivity Index
PPA	power purchase agreement
PPI	Producer Price Indexes
ROP	rate of penetration (during drilling)
SNL	Sandia National Laboratory
SSR	stimulation success rate

WF	working fluid
WFPSF	working fluid pumps scaling factor

GETEM User Manual

1. Department of Energy's Geothermal Electricity Technology Evaluation Model (GETEM)

1.1 Background

The Geothermal Electricity Technology Evaluation Model (GETEM) estimates the representative costs of generating electrical power from geothermal energy. The estimated costs are dependent upon a number of factors specific to the scenario being evaluated, with most of these factors defined by inputs provided. Based on the scenario characterization, cost estimates are developed for all aspects of a project needed to provide the specified or calculated power sales. These costs and annual power sales are the basis for determining a levelized cost of electricity (LCOE).

The driver for GETEM's development was to allow the U.S. Department of Energy's Geothermal Technologies Office (GTO) to comply with the Government Performance and Results Act of 1993 (GPRA). GETEM allows GTO to annually assess, quantify, and report the impact of improvements that have occurred with geothermal power generation. In addition, identifying the different contributors to the cost of electricity generated from geothermal energy contributes to GTO understanding of how technology improvements affect generation costs. This assists GTO in developing a research portfolio that provides an optimal return on the investment of taxpayer dollars in its research program.

GETEM was originally developed from 2004 through 2006. A team led by Dan Entingh from Princeton Energy Resources International developed the original model. This team included individuals from industry and the national laboratories who had experience and expertise in different aspects of geothermal project development. At that time, the focus was on developing representative power generation from hydrothermal resources using either flash steam or air-cooled binary conversion systems (plants). For lower-temperature resources, GTO has placed focus on the development of the air-cooled binary technology. Largely because of this emphasis, the binary cycles depicted in GETEM were and continue to be air-cooled.

Initial development efforts ended in 2006, but resumed in 2008 with an emphasis on characterizing generation costs from EGS resources. With resumption of work, all aspects of the model's development of cost and performance estimates were reviewed and revised where necessary. During this period, the approach for determining generation costs for air-cooled binary plants was modified. The cost and performance of a binary plant is a tradeoff between increasing the amount of power that can be produced from a given geothermal flow rate, and the additional capital costs associated with the more efficient designs. This tradeoff is incorporated into GETEM, in which the impact of performance on both plant costs (which vary directly with performance) and well field costs (which vary indirectly) are considered in establishing the level of performance that minimized the LCOE.

In 2011, GTO revisited the model development in response to industry concerns that its estimates did not adequately reflect the costs to discover a commercially viable hydrothermal resource. From 2011 to 2013, a LCOE analysis team led by Jay Nathwani from GTO conducted a series of interviews with industry subject-area experts to validate both the approaches used in GETEM and the reasonableness of costs that were estimated for the different aspects of project development. Resulting additions and revisions included the following:

- Methods for estimating well costs were revised to reflect the recent well costs provided to the team by Sandia National Laboratory.
- A down-select process was added in which multiple prospects are considered and drilled in order to develop a commercial project.

- Power generation costs are now estimated using a discounted cash flow approach developed by the Department of Energy (DOE) for its Office of Energy Efficiency and Renewable Energy (EERE) programs.

The latter two changes allowed GTO to assess the impact of risk of failure in discovering a commercially viable resource. Including the costs incurred at failed prospects increases the costs associated with the exploration phase, while the discounted cash flow methodology allows higher discount rates to be applied to the costs occurring during the early project activities when risk is the greatest. Their effect is to increase the present value of the costs associated with exploration and the contribution of those costs to the project's LCOE

Prior to this work, GTO did not have specific scenarios defined for assessing the impact of technology on generation costs. As part of the interviews with industry, information was solicited to validate or revise, as necessary, model inputs to account for the variability in resource quality (temperature and productivity) and resource depth. From this information, GTO developed specific EGS and hydrothermal resource scenarios that are the basis for evaluating the impact of recent (for GPRA reporting) and future technology advances on generation costs. The resource scenarios defined are shown in Table 1 below.

Table 1. Resource scenarios for assessing impact of technology on generation costs.

Scenario	Project Life (yr)	Temperature (°C)	Depth (km)	Flow Rate (kg/s)	Production/ Injection Ratio	Plant Type	Power Sales (MW)
EGS A	20	100	2	40	2 to 1	binary	10
EGS B	20	150	2.5	40	2 to 1	binary	15
EGS C	20	175	3	40	2 to 1	binary	20
EGS D	20	250	3.5	40	2 to 1	flash	25
EGS E	20	325	4	40	2 to 1	flash	30
Hydro A	30	140	1.5	100	4 to 3	binary	15
Hydro B	30	175	1.5	80	4 to 3	flash	30
Hydro C	30	175	1.5	100	4 to 3	binary	30
Hydro D	30	225	2.5	80	4 to 3	flash	40
Hydro E	30	140	2.5	100	4 to 3	binary	15

For each resource scenario, the LCOE analysis team developed a unique set of inputs for GETEM. Subsequent to this work, added emphasis was placed on validating both the model estimates and inputs.

One issue with the earliest versions of the model was the use of fixed values in the calculations that could not be changed and were not always apparent to users. When development work resumed in 2008, these fixed values became model inputs. This practice continued through the work done by the LCOE analysis team. When work by this analysis team was completed, there were ~240 inputs to the model, making GETEM intimidating to use if one lacked sufficient experience and expertise to provide representative inputs for all elements of the geothermal project development.

To facilitate the broader use, default inputs were developed based on the work done by the LCOE analysis team and subsequent validation efforts. At present, GETEM defaults to a specific set of inputs that are based on the specified resource type, temperature, and depth. Of these defaults, 113 can be revised by the user. These inputs were selected for possible revision based on sensitivity analyses done for both EGS and hydrothermal scenarios to identify those inputs having the greatest impact on the LCOE.

In 2015, the model's depiction of project development was aligned with the *Geothermal Handbook: Planning and Financing Power Generation,* (ESMAP 2012). The modifications did not significantly alter the characterization of the different project activities, but rather changed the timing of the activities (and when their costs are incurred). Obtaining a power purchase agreement (PPA) is now the focal point for depicting the project development and establishing when project costs are incurred.

GETEM is made available to the public with the expectation that any issues with the model's depiction of a project, or the reasonableness of its estimates, will be conveyed to GTO. While GETEM can be amenable to evaluating a specific project, a user should recognize that the model's estimates are a representative depiction of a project for the scenario defined. If more than a representative estimate is required for a specific site, those estimates should be made based on the characteristics of that specific site by entities whose business is to perform such evaluations. The values that are provided by GETEM should not be considered or represented as an official DOE estimate of either cost or performance for a specific project.

1.2 Model Description

GETEM is an Excel-based tool that estimates the LCOE for a defined geothermal scenario. Only the generation of electrical power is considered, where the sole source of heat to the power cycle is the geothermal resource. An evaluation is made for either a hydrothermal or an EGS resource, and for either a flash steam or air-cooled binary power plant. GETEM does not evaluate generation costs for water-cooled binary plants or air-cooled flash plants.

With a resource type, temperature, and depth specified, a set of default inputs are established. These inputs, and any revisions made to them, are the basis for the characterization of performance and costs for the different aspects of project development. Two estimates are made: one based on the default inputs (default scenario), and the second based on any revisions made to the default inputs (revised scenario). The only instance when the default scenario changes is if the conversion system is changed from the model default. Costs and performance for both the default and revised scenarios are based on the same resource and conversion system.

Though input can be provided in combinations of SI and Imperial units, calculations are made in Imperial units. Results are provided in Imperial units, though several are given in both sets of units.

All costs are in U.S. dollars. The inputted and calculated costs used to determine the LCOE are "overnight" values; inflation is not incorporated into any of GETEM's estimates. A discounted cash flow (DCF) methodology is used to determine the LCOE. The present value of costs and revenues are determined at startup using specified discount rates for each phase of the project and a schedule of project activities. Though GETEM retains the fixed charge rate (FCR) methodology initially used to determine generation costs, the LCOE reported by the model is based on the DCF approach.

Each default cost is based upon a specific year, and is adjusted to the year for which the project is being evaluated using a Producer Price Index (PPI) obtained from the Bureau of Labor Statistics (United States Department of Labor). If a default costs is revised, the revision needs to be in the year selected for the scenario evaluation (i.e., PPIs are not applied to revised costs). The PPIs allow projects to be evaluated in prior years (back to 1995) to facilitate evaluation of existing facilities. Though GTO periodically updates the PPIs in GETEM, this may not continue in the future. The specific PPIs from the Bureau of Labor Statistics used are listed in the model (in the *Tables* worksheet) to facilitate a user's maintaining the most current values.

The estimates of the LCOE for power generation do not consider incentives that may be available for renewable power generation.

Three levels of power output are used. Power sales are the amount of electricity delivered to the power grid for sale. The magnitude of the power sales is the net plant output less the geothermal pumping power. The net plant output is the generator output less the plant-specific parasitic power requirements to operate fans, pumps, and other power consumption within the plant. The net plant output is the basis for the plant size needed to provide a specified level of power sales. The generator output (nameplate capacity) is estimated in order to size and cost the turbine-generator set; it has no other use in GETEM.

$$Power\ Sales = Plant\ Power_{net} - Pumping\ Power_{geo-fluid}$$
$$Plant\ Power_{net} = Generator\ Ouput - Parasitic\ Power_{plant}$$

The well field characterization is based on all successful production or injection wells being identical. Production wells have the same depth, the same casing configuration, flow rate, temperature, and productivity index. The injection wells are similarly assumed to be identical. These parameters may differ between an injection well and a production well. GETEM has no criteria for well success other than it have the flow, temperature, and productivity/injectivity specified.

The estimates of power generation over the life of the project are based on the premise that the resource temperature declines with time, while the geothermal flow rate remains constant. Makeup drilling can occur if the temperature decline is excessive; when this drilling occurs, the entire well field is replaced and the production temperature is assumed to return to the initial, specified value.

Because GETEM's purpose is to provide representative costs in lieu of evaluating a specific project, fractional wells, staff, and equipment are utilized. Though there is limited flexibility to revise selected inputs and specify fixed integer values, the default scenario uses the calculated fractional values.

Most GETEM worksheets are password protected. This is done to (1) assure that input revisions are made in the correct location within the model, and (2) maintain a level of control on the model to assure that there are not revised versions of the model being used to provide GETEM estimates.

Those portions of the model in which a user can make revisions or updates do not have password protection. To allow the macros to run, some worksheets are protected, but do not have passwords.

1.2.1 Geothermal Project Depiction

In GETEM, the project development occurs in the following phases, with a unique duration and discount rate applied to each:

1. Discover and establish a viable resource
2. Develop the project to the point necessary to obtain a PPA
3. Complete the project development once the PPA is obtained
4. Operate the facility.

The characterization of these phases of a project includes the activities and elements shown below (Figure 1). Costs are estimated (or inputted) for the activities in each project phase. These costs, along with the estimated power generation over the project's life, are the basis for the LCOE estimate for the defined scenario.

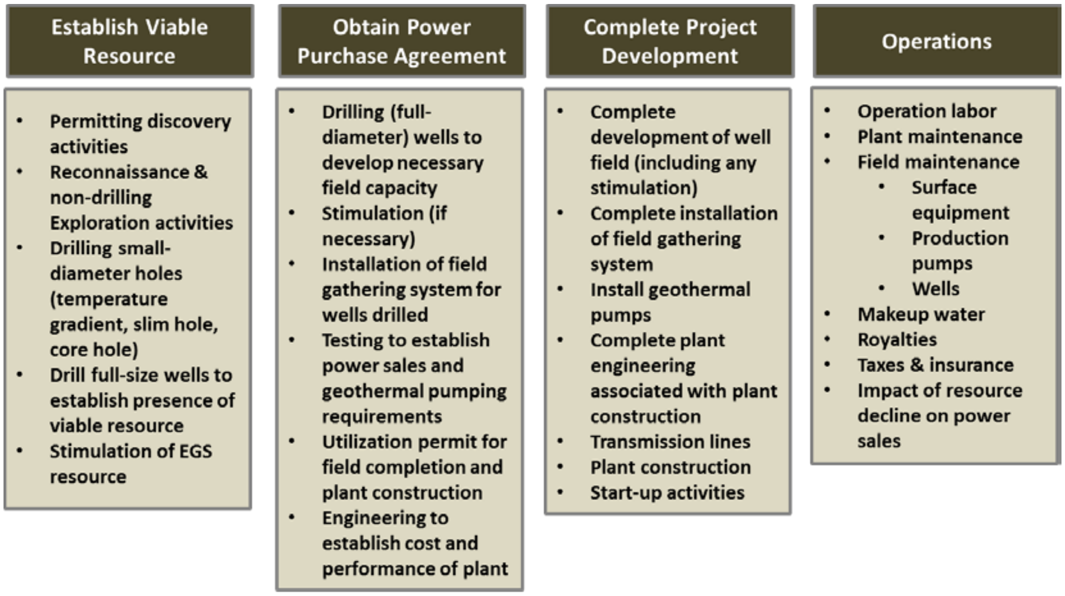


Figure 1. GETEM's characterization of a geothermal project's development.

Within GETEM, the first of these phases (shown in Figure 1) is referred to as exploration and confirmation. The second phase includes a portion of GETEM's well field development or drilling. The third phase completes GETEM's well field development and includes the power plant construction. These terms have been used throughout GETEM's development to refer to the specific phases of a project.

1.2.2 Approach

A project evaluation is based either on a specified level of power sales or on a specified number of successful production wells. The model defaults to using a specified level of sales, with the option to consider a different level of sales or to use a fixed number of wells. Whichever is specified is the basis for sizing the project for the revised scenario. Once the project size is determined, the capital and operating costs are estimated for the power plant and the well field.

1.2.2.1 Sizing Project. Figure 2 below shows the basic approach used to size a project based on the level of sales. Unless revised, a default sales value is used (based on resource type, resource temperature, and plant type). The elements across the top of this figure are either specified (resource depth and temperature) or default values that can be revised. The other elements shown are values that the model determines based on these input and/or default values.

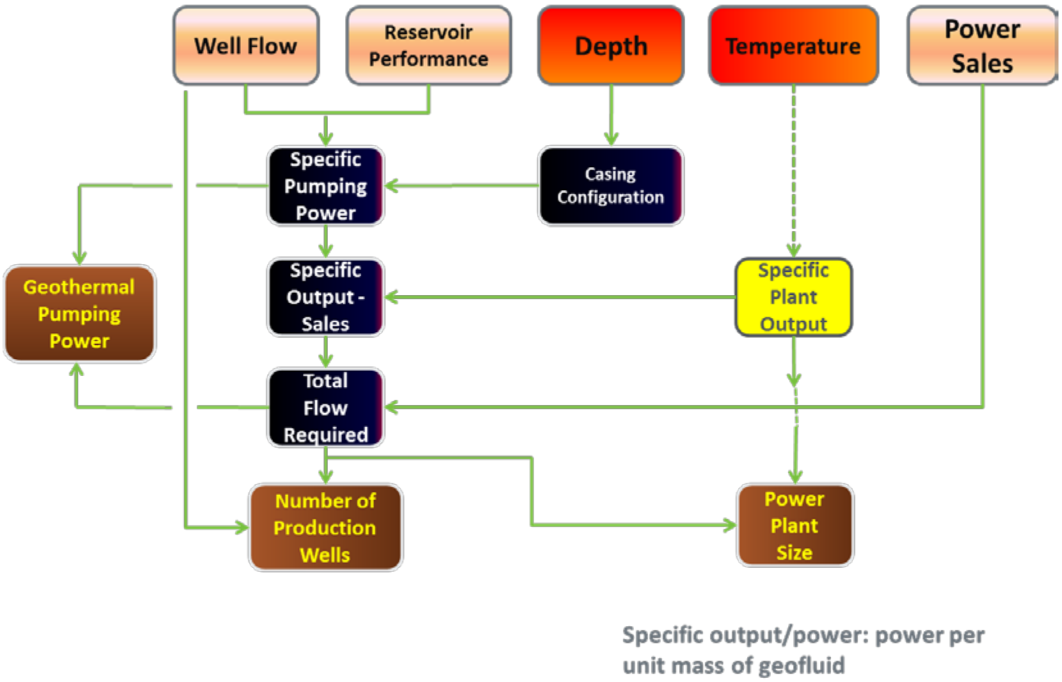


Figure 2. The approach for sizing a project based on level of power sales.

The following summarizes how this approach determines the geothermal pumping power, the plant size, and the number of production wells needed.

1. From the resource depth, a default casing configuration is established for the production and injection wells. A user has limited ability to adjust this default configuration.
2. The specific pumping power is determined:
    a. The casing configuration and the flow rate per well are used to estimate the frictional pressure losses for flow in the well bore.
    b. The flow per well and the reservoir productivity and injectivity indices are used to determine the reservoir drawdown at the production well and the buildup at the injection well.
    c. The frictional losses and reservoir drawdown and buildup, along with the resource depth and temperature, are the basis for the determination of the specific pumping power (pumping power per unit mass flow of the geothermal fluid). This value includes both production and injection pumping requirements.
3. Then the specific output (based on sales) is calculated:
    a. The specific output, based on sales, is the sales per unit mass flow of the geothermal fluid produced. It is the difference between the specific plant output and the specific pumping power.
    b. The specific plant output is the net output from the plant per unit mass of produced geothermal fluid (also called brine effectiveness in the GETEM). This value is calculated for flash plants

based on flash pressures (established by the resource temperature) and model inputs (default or revised). The specific plant output is the performance metric for the binary plant that is either inputted or determined by GETEM.

   c. The specific pumping power is the geothermal pumping power per unit mass of produced flow. It is calculated from the total pumping power determined for a single production and injection well and the flow from an individual production well.

4. The total geothermal flow required is determined from the power sales and the specific output based on sales.

5. The number of successful production wells required is determined from the total geothermal flow rate required and the flow rate per production well.

6. The total geothermal pumping power is determined from the total geothermal flow rate required and the specific pumping power.

7. The power plant size is determined from the total flow rate and the specific plant output.

When the evaluation is based on a fixed number of wells, the total flow is known. That total flow and the specific pumping power are used to determine the total geothermal pumping power. The total flow and the specific plant output establish the power plant output (size). The difference between the plant output and the total geothermal pumping power is the sales that result from the number of production wells specified.

1.2.2.2 Capital Costs. GETEM estimates the capital costs for the following phases of the project development:

- Exploration
- Drilling to complete well field
- Field gathering systems for the geofluid
- Power plant construction.

The capital costs that are included in GETEM's determination of an LCOE are summarized in Figure 3. All costs used to determine the LCOE can be revised by a user, regardless of whether they are default values or calculated by GETEM. A user cannot, however, alter how GETEM estimates costs.

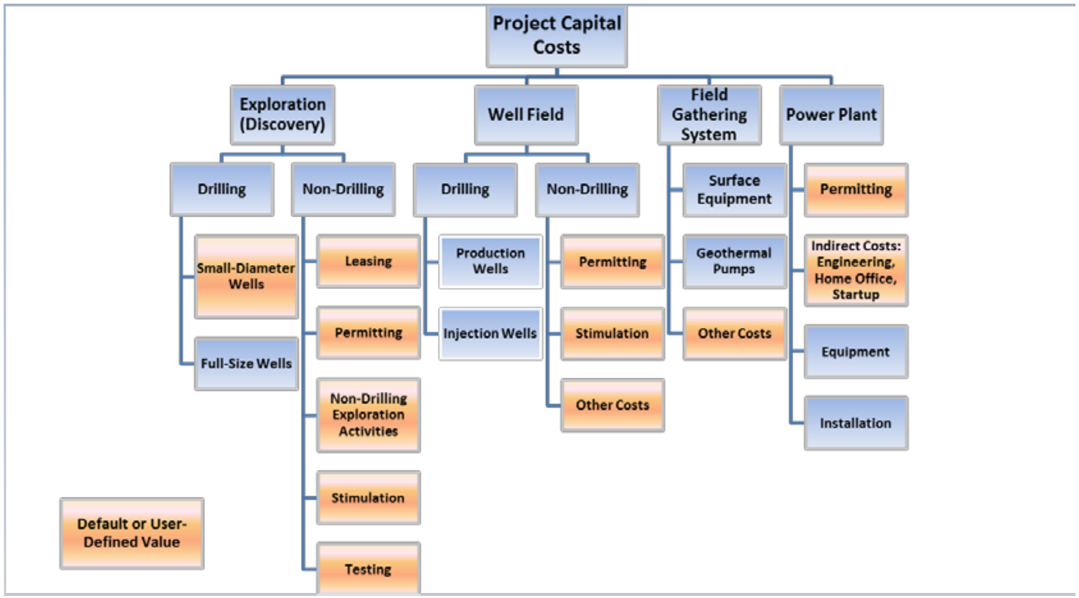


Figure 3. Capital costs included in GETEM's determination of an LCOE.

With the exception of the costs for drilling full-size wells, a contingency is applied to all capital costs in the LCOE determination. The level of contingency applied to the non-drilling costs is an input that can be revised. The correlations used to estimate well costs include a contingency term (which cannot be revised). If a user adjusts the estimates of well costs, the revised value should also include any expected contingency needed for drilling the wells.

Exploration (Discovery):

GETEM assumes that all projects evaluated are Greenfield projects. When a potential resource is discovered, it is not known whether the resource is commercial, and if so, what level of power production can be sustained. As such, the costs determined for this portion of project development are not dependent upon the size of the project.

To find a commercial resource, it may be necessary to evaluate and drill multiple prospects. In order to assess how exploration activities and GTO R&D efforts could impact a project's LCOE, a down-select process was incorporated into GETEM. This process is depicted below in Figure 4. In order to develop a successful project, multiple sites are initially evaluated, with some of those sites having drilling activities.

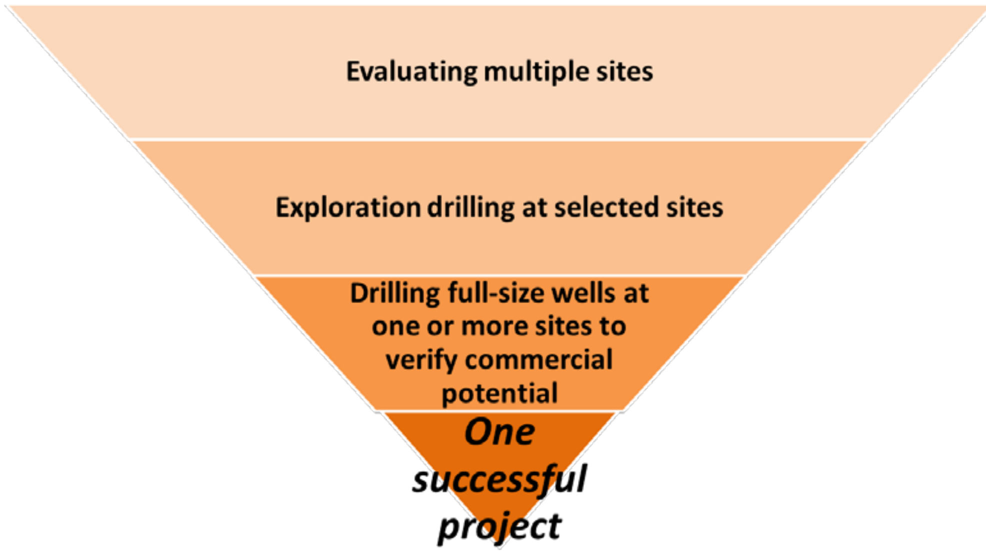


Figure 4. Down-select process option used by GTO to evaluate impact of exploration R&D on LCOE.

GETEM's current characterization of the exploration phase includes the upper three activity levels shown in this figure. When this down-select process is used, the capital costs for exploration include those incurred at the unsuccessful sites that are evaluated and drilled, but not developed. If there are multiple unsuccessful sites with drilling, the impact of including their costs on the LCOE can be dramatic. Though the exploration costs for Greenfield resources are not considered a function of the size of the project that is developed, these early project costs will determine the size of a project that is needed in order for the project to be commercially viable.

While the impact of this down-select process on the LCOE can be evaluated, the current default is based only on those costs incurred at the successful site. Costs at this site include those for initial exploration activities, permitting and leasing, drilling of small diameter wells (e.g., slim holes, core holes, and temperature gradient wells), and the drilling and testing of a limited number of full-sized wells to establish that the resource is commercially viable. The LCOE estimate does not include those sites considered but not developed unless the user opts to include the costs incurred at those sites in the revised scenario.

Though it is not the default, GETEM allows for the evaluation of in-field expansion projects as well. If these projects are evaluated, the user will specify those exploration activities to be included in the evaluation.

The costs for the exploration activities are primarily specified inputs; the only calculated cost is that for full-size wells, which is based on the specified resource depth. All default costs can be revised, including the cost of the full-sized wells.

Power Plant and Well Field:

Once the project size is established, capital costs are estimated using the approach depicted below in Figure 5 (for a binary plant). The elements shown on the left side of the figure are the basis for determining the plant and well field capital costs. These values are either inputs or determined when sizing the project.

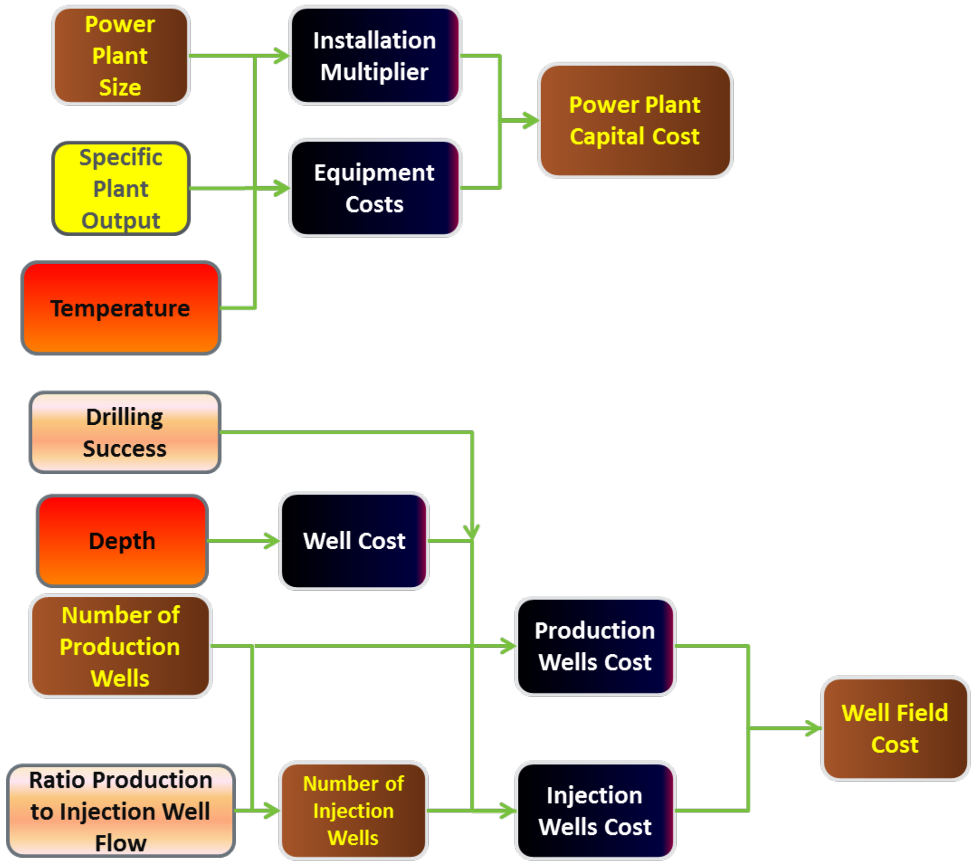


Figure 5. The approach for estimating capital costs for a binary plant.

The binary power plant capital cost is a function of the plant size, the specific plant output, and the resource temperature. Equipment costs are determined as functions of the plant's second law efficiency, which is determined from the specific plant output and the resource temperature. The equipment costs for the binary plant vary directly with this second law efficiency (i.e., a more efficient power plant is more expensive). The total geothermal flow rate required for the sales varies inversely with the specific plant output (and the second law efficiency). Hence, a more efficient plant may have higher plant equipment costs, but will need less flow, fewer wells, less geothermal pumping power, and a smaller plant size to produce a specified level of sales. A macro in GETEM performs this tradeoff for the binary plants with the specific plant output varied until the LCOE for the specified scenario is minimized.

For the specific output, GETEM determines the cost of the major equipment items and an installation multiplier. This installation multiplier includes both the direct construction costs and the indirect costs, including engineering, home office, and startup. This installation multiplier is applied to the equipment cost estimates to determine the installed cost of the plant needed to provide the sales specified.

With flash plants, costs and performance estimates are based on flash pressures that are either determined by the model or inputted by a user. These pressures, along with estimates of heat rejection and parasitic power requirements, are used to determine the equipment costs. An installation multiplier is applied to the equipment costs to obtain the installed flash plant cost.

This approach for determining installed plant costs by estimating equipment costs and applying an installation multiplier was adopted from Electric Power Research Institute's *Next Generation Geothermal Power Plants* study (EPRI 1996). The installation multipliers used are specific to the type of power plant, and are determined using the resource temperature and plant size. This multiplier can be revised.

Once the specific power plant output is established, the number of production wells required is determined (see the previous section on sizing a project). The ratio of the production to injection well flow rates, a production well flow rate, and the total flow injected are used to determine the number of injection wells required. From the depth of the well, a well cost is estimated. If the production and injection wells have different depths or casing configurations, their costs will differ. GETEM assumes that all production wells drilled have the same individual cost, regardless of whether or not they are successful. The same assumption applies to all injection wells.

A drilling success rate is used to determine how many wells must be drilled to provide the required number of wells. Unsuccessful wells drilled for a hydrothermal resource can be used to supplement injection. If this option is used, the number of successful injection wells required is decreased, though the number of wells used for injection will increase. This is not an option for EGS resources.

Once the total number of production and injection wells drilled is determined, the individual well cost is multiplied by the total of each type to determine the total production and injection well costs. Their sum is the total drilling cost for the well field. The total well field cost will also include permitting, testing and indirect costs (e.g., engineering, management, and home office).

Note that in the simplified depiction shown in Figure 5, there is no indication of when drilling costs are incurred. GETEM assumes that during the exploration phase for a Greenfield project, one or more full-sized wells that will support power plant operation are drilled. It is also assumed that some portion of the total field capacity must be developed to obtain a PPA; this fraction of capacity needed to obtain the PPA is an input.

Geofluid Field Gathering System:

Costs for the geothermal gathering system are based upon the number of wells being used to support the plant operation. Each well utilized has an associated cost for the surface equipment. This surface equipment cost is determined using an inputted average distance between the plant and well, and an estimated piping size for the specified production well flow rate. This cost per well is multiplied by the number of wells used to determine the total surface equipment cost.

When a binary plant is used, it is assumed that a downhole pump is used with each production well; flash wells default to not using production pumps. The pump setting depth is based on the casing configuration, well flow rate, well depth, fluid temperature, and the productivity index used. This setting depth, well flow rate, and pump efficiency establish the size in horsepower (hp) of the production pump; this size is the basis for the estimated pump cost. The estimated cost does not differentiate between line-shaft and electric submersible pumps. The total cost for production pumps is the product of the estimated pump cost and the number of production wells in service.

An individual injection well is similarly evaluated using the well flow rate, casing configuration, fluid temperature, well depth, and injectivity index to determine the injection well-head pressure needed. This pressure, the total injection flow, and a pump efficiency are used to determine the injection pumping power. Injection pumping is assumed to be provided at a single location using one or more pumps (the model assumes a maximum pump size of 2,000 hp, with more than one pump used if the total power required exceeds this limit). The size (in hp) determined for an individual pump is used to determine the cost of a single pump; the total injection pump cost is the product of the cost of a single pump and the number of injection pumps required.

The cost for the geothermal gathering system is the sum of the surface equipment costs (for both production and injection wells), the total production pump cost, and the total injection pump cost. If spare wells are specified, it is assumed that they will be production wells, and the costs for any production pump and surface piping will be included for each spare well specified. In addition, the total field gathering system includes an indirect cost that is a specified percentage of the total cost.

Indirect Costs:

The different phases and activities in project development will have costs that are difficult to categorize and assign a specific value. These costs include planning and management activities, limited testing of exploratory wells, engineering, and other similar expenditures; they also include those costs, exclusive of permitting, associated with obtaining a PPA. Indirect costs are estimated as a percentage of the total cost for the activity or phase. These percentages are specified inputs for each project phase.

1.2.2.3 Operating Costs. The operating costs used in estimating the LCOE include:

- Operating labor costs: staffing for plant and well.
- Maintenance costs: a specified fraction of the capital costs for
  - the power plant,
  - the well field
  - the field gathering system.
- Production pump maintenance: the operating life of a production pump, based upon the type of pump specified. Line-shaft pumps are assumed to have a longer operating life, though this pump type also has a cost for the oil (water-soluble) used to lubricate the shaft bearings.
- Makeup water costs: the unit cost for water, which is a function of the resource type and the type of power conversion system utilized, as is the amount of water that must be made up.
- Property taxes and insurance: based upon the total capital cost for the power plant, surface equipment, geothermal pumps, and wells that support the operation of the facility. Exploration costs, aside from the costs of full-size wells supporting plant operation, are not included. Neither are the costs for failed wells not used to operate plant. Any stimulation costs for wells supporting the plant operation are included.
- Royalties: based on the Bureau of Land Management (BLM) royalty schedule.

The inputs used to determine the operations and maintenance (O&M) costs can be revised, or a total O&M LCOE contribution ($ per kW · h) can be specified.

There is further discussion on GETEM's determination of both capital and operating costs in the Appendices.

1.2.3 Model Layout

GETEM contains multiple worksheets in which information is inputted, calculations are made, and results are presented. The worksheets in the model are described below in Table 2:

Table 2. GETEM worksheets and their purposes.

Sheet	Purpose
GETEM-Read Me	General information on model.
Start Here	Resource and conversion system are specified. Hyperlinks to specific model inputs on Scenario Definition.
Scenario Definition	Changes or revisions to model defaults for different phases and elements of project.
Results	Summary of LCOE contributions and capital costs.
Error-Warnings	Summary of potential issues with revisions made on Scenario Definition.
Schedule	GETEM's schedule of main project activities and graphical representation of when costs are incurred.
EERE-COE	Calculation of cost of electricity (COE) using approach provided by DOE EERE for renewable energies.
DCF-COE	Simple discounted cash flow to determine COE.
FCR-Binary Output	Results when using Fixed Charge Rate to determine LCOE for binary projects.
FCR-Flash Output	Results when using Fixed Charge Rate to determine LCOE for flash steam projects.
Out LCOE	Summary of calculated, default, and revised values used to calculate LCOE.
OUT	Worksheet providing location for staging calculated values and inputs that are the basis for dependent calculations.
IN	Worksheet providing location for staging default values for specified resource and conversion system and user revisions to those defaults.
Tables	Listing of producer price indexes used in the model.
Binary A1	Worksheet with macro that solves for binary plant performance that minimizes LCOE.
DEFAULT Inputs	Listing of all default values in model. Values are selected from listing based on the resource and power plant types defined; they cannot be changed.
Geofluid	Summary of geothermal fluid property calculations, including available energy, silica solubility temperatures, and injection fluid temperature.
Exploration	Compilation of calculations (including costs) costs associated with the exploration phase.
Well Count	Calculation of the number of wells drilled and stimulated prior to and after obtaining a power purchase agreement (PPA). Includes impact of using failed wells to supplement injection.
Drilling Costs	GETEM's estimate for the production and injection well cost. Includes determination of total stimulation cost (if wells stimulated). Sheet also includes casing configuration used to determine well frictional losses when sizing pumps.
Field Gathering System	Estimates of the surface equipment cost and geothermal pump costs.
Resource Definition	Summary of calculations for flow rate, makeup water, reservoir drawdown and buildup, and temperature decline.

Table 2. (continued).

Sheet	Purpose
GF Pumping	Determination of injection pumping pressure and production pump setting depth. Pump sizes (in hp) and costs determined.
Power Plant Cost	Import estimates of power plant equipment costs and determination of power plant costs. Determination of the engineering costs used.
O&M	Estimate operations labor and maintenance costs for the project.
dT in Prod Well	Estimate the ΔT of production fluid in well bore due to heat loss to surrounding earth. Wellhead temperature is used in sizing project and costing plant.
Binary Power Plant	Estimates equipment costs and installation multiplier for the binary power plant.
Flash Plant Performance	Determination of the flash plant pressures, power generation, parasitic loads, and heat rejection requirements.
Flash Plant Cost	Estimate of equipment costs based on the calculated equipment sizes. Determination of the installation multiplier used to determine equipment costs.
DrwDwn Summary	Summary of the effect of the temperature decline, or draw-down (DrwDwn), on plant output. Information taken from calculations for both binary plants and flash plants. Information exported to OUT worksheet, from which other worksheets access information in determining the LCOE.
Reservoir – Binary	Estimate of the impact of the resource temperature decline on power output; determination of the timing for replacement of the well field (if required).
Reservoir – Flash	Estimate of the impact of the resource temperature decline on power output; determination of the timing for replacement of the well field (if required).
LCOE Binary	Calculation of LCOE for binary projects using FCR methodology.
LCOE Flash	Calculation of LCOE for flash steam projects using FCR methodology.

1.2.4 Defining a Scenario for Evaluation

The scenario to be evaluated is defined on two worksheets: *Start Here* and *Scenario Definition*. These are the only worksheets on which changes should be made to the calculated or default values that are used in estimating the LCOE.

1.2.4.1 Start Here. On the *Start Here* sheet, the resource type, temperature, and depth are specified. When units are shown with a yellow background, they can be changed. Each of these cells has a dropdown listing of the units in which the input can be provided; these are the only unit options available.

Figure 6 shows a screenshot of this worksheet. The minimum inputs required to evaluate a project are those cells with the yellow background—the resource type (hydrothermal), the resource temperature (175°C) and the resource depth (1,500 m). From this input, a set of default values are developed that result in an LCOE of 10.01 ₵/ kW · h as shown at the top of the worksheet. Shown on this sheet is the default conversion system (binary). If the flash steam conversion system is to be used, it is selected from the dropdown menu in the cell with the yellow background below the cell showing that the default is a binary plant. The dropdown shows that one has the option of selecting *Flash*, *Binary*, or leaving the cell blank. If left blank, the default is used. This default is based on the resource type and the resource temperature. For EGS resources with temperatures of 200°C and lower, a binary plant is the default. If the resource is hydrothermal and the temperature is 200°C or higher, the default is a flash plant. There is an expectation that, with EGS resources, the air-cooled binary plant will be used with higher temperature resources because of the necessity of making up surface water losses. At present, the 200°C limit is approximately the upper limit for production pump technology. This is also the upper resource temperature used in developing the binary plant cost correlations.

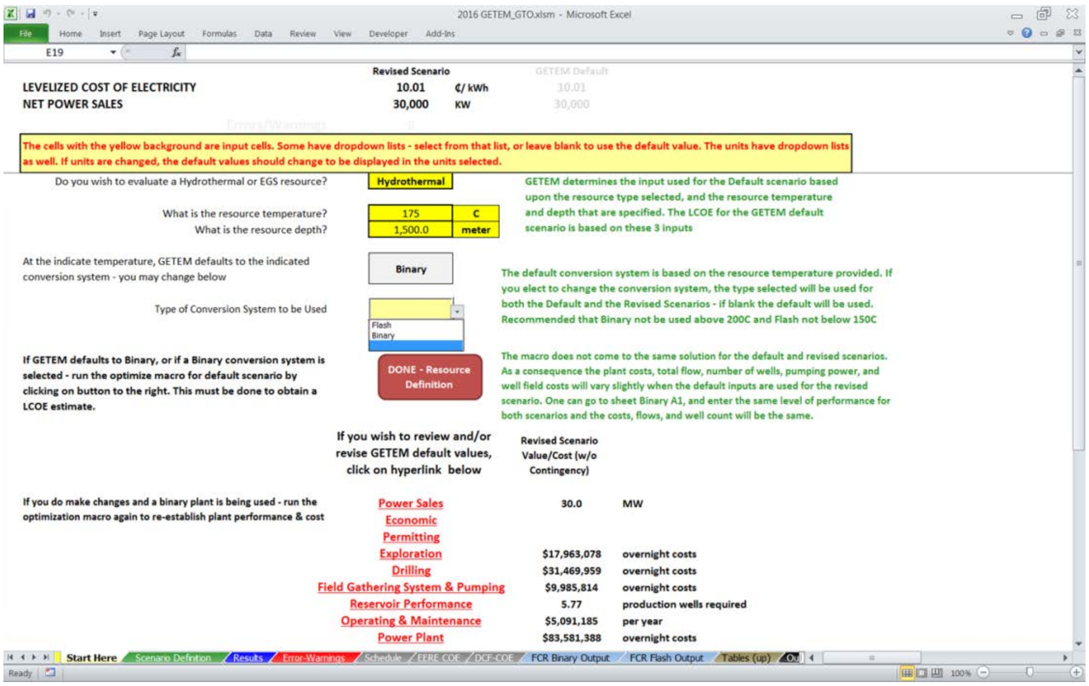


Figure 6. Screenshot of the *Start Here* worksheet.

Just below the LCOE at the top of the page are the power sales for the revised and default scenarios. For this example, the power sales are at the default value of 30 MW. Information and comments are provided in the green font on to the right of the cells where inputs are provided or revised; comments are provided in a similar manner throughout the model. The different project elements shown in red font near the bottom of this screenshot are hyperlinks to the default inputs on the *Scenario Definition* worksheet. To the right of these links are model results for an important cost or performance value determined using the current input for that portion of the input associated with the hyperlink.

As an example, the input that is being used to develop the indicated cost for drilling can be reviewed by clicking on the *Drilling* link, which takes one to the inputs for the *Drilling Activities*, shown below in Figure 7.

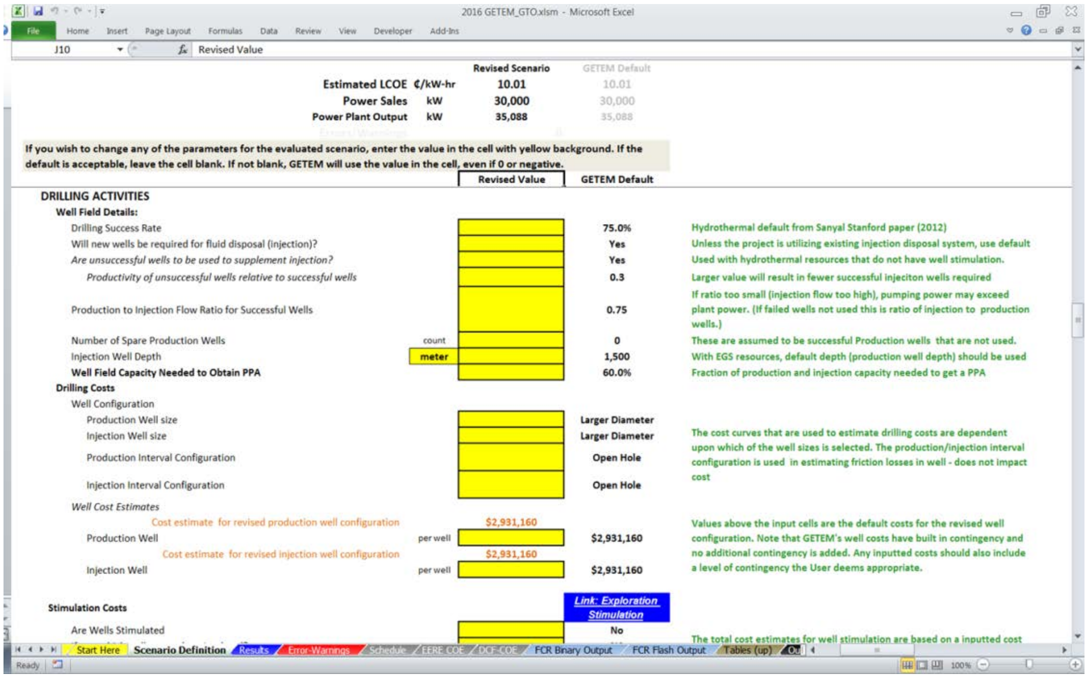


Figure 7. Screenshot of the *Drilling Activities* sheet.

Again, comments regarding specific inputs are on the right in the green font. Any revisions to the default values are made in the cells with the yellow background immediately to the left of the defaults. To illustrate how changes are made, consider a scenario in which smaller diameter production wells are used and the flow rate in each successful injection well is twice that of a production well. The input for the production to injection flow ratio is revised to 0.5 and smaller diameter wells are used, as shown below in Figure 8.

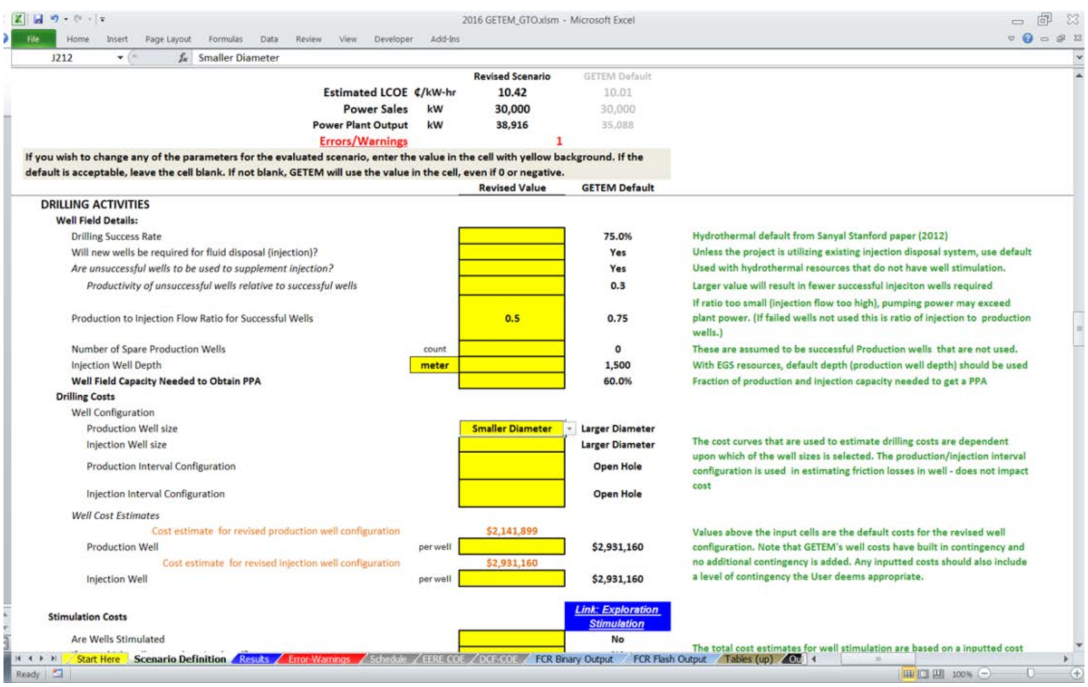


Figure 8. Screenshot of *Scenario Definition* with two revisions of the default inputs.

With the change to the production well size, the production well cost is reduced from $2.93M to $2.14M. With the change in the flow to the injection wells, the injection well count is reduced; however, both of these changes increase the amount of geothermal pumping required, resulting in a larger, more expensive plant and increased total brine flow in order to provide the specified power sales. For this scenario, the plant size increased by ~3.8 MW and the number of production wells required increased from 5.77 to 6.40. The higher injection well flow rate decreased the number of injection wells from 3.56 to 2.47. The combined effect was a more expensive project with a higher LCOE.

Going back to the *Start Here* sheet and scrolling down, a summary is of the revisions made to the default values is provided as shown below in Figure 9.

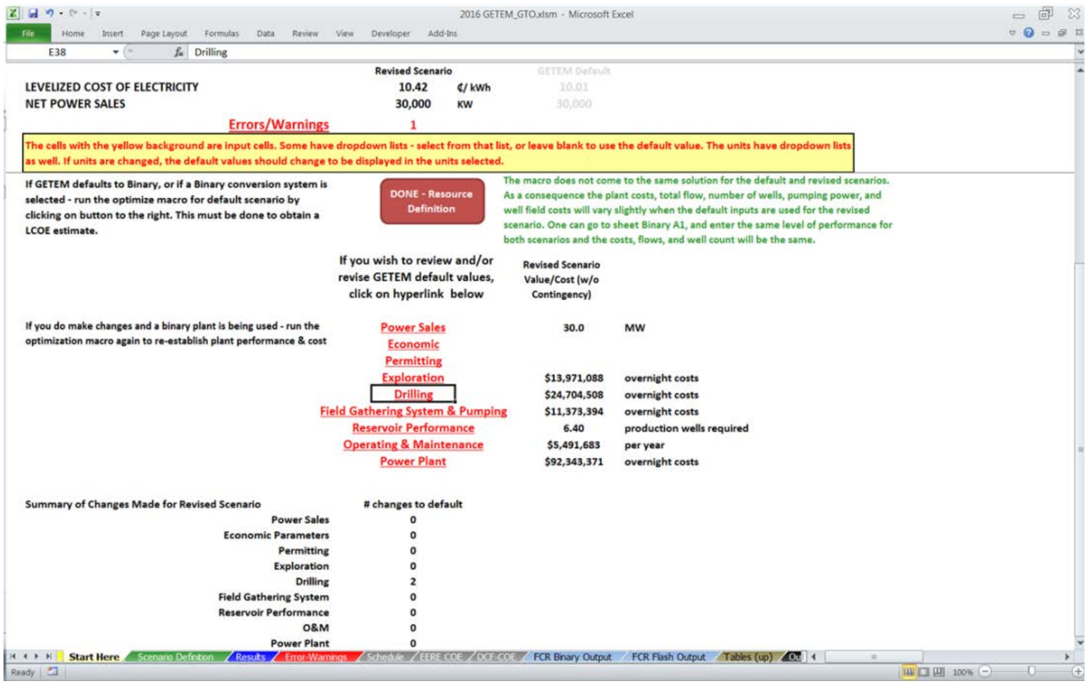


Figure 9. Screenshot of the *Start Here* worksheet after revisions made to the default values.

This shows that the two default inputs have been revised for *Drilling*. Though the specific changes are not identified, one can see that changes were made in this input section, and by using the *Drilling* link, the specific changes can be found.

The effect on both plant size and LCOE is shown at the top of this sheet. Immediately below the *Power Plant Output* is a flag (*Error/Warnings*) that indicates there is one potential issue with one input provided. *Error/Warnings* is a hyperlink that takes one to another sheet with those errors or warnings listed (see Figure 10). The message given states that for the resource depth specified, an upper casing diameter is determined that is less than the minimum casing size needed for a production pump. At this resource depth, the smaller diameter wells should not be used with binary plants.

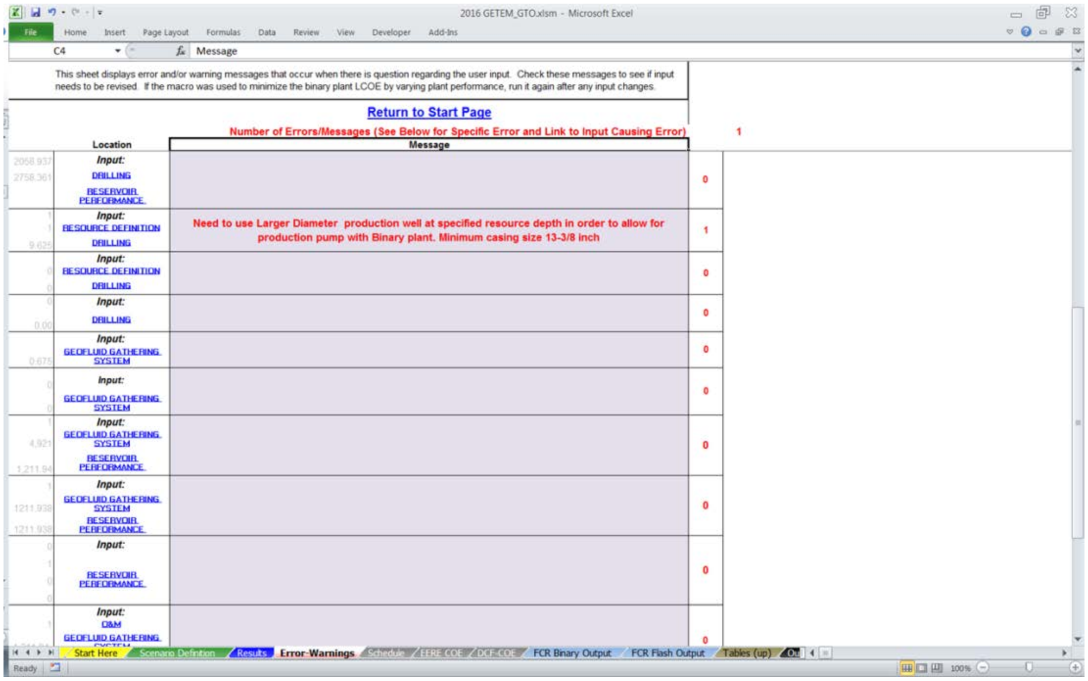


Figure 10. Screenshot of worksheet showing errors and warnings.

To correct any issues or potential issues identified with the inputs provided, hyperlinks are provided to the left of each message. To correct this issue, the link to the *Drilling* input on the *Scenario Definition* sheet is selected and the change to the production well size is removed. Returning to the *Start Here* sheet, the *Error/Warning* messages have cleared.

When a binary power conversion system is being used, once all changes to the inputs are made, return to the *Start Here* sheet and click on the *Done - Resource Definition* button, illustrated in Figure 11. This runs the macro that identifies the level of plant performance that minimizes the LCOE for both the default and revised scenarios.

Figure 11. The *Done - Resource Definition* button, which is the last step after providing all revisions to GETEM default values (on the *Start Here* worksheet).

The *Start Here* sheet after running the macros is shown below in Figure 12

. This shows that, despite the injection wells taking more flow (and presumably decreasing the number of injection wells), the LCOE has increased.

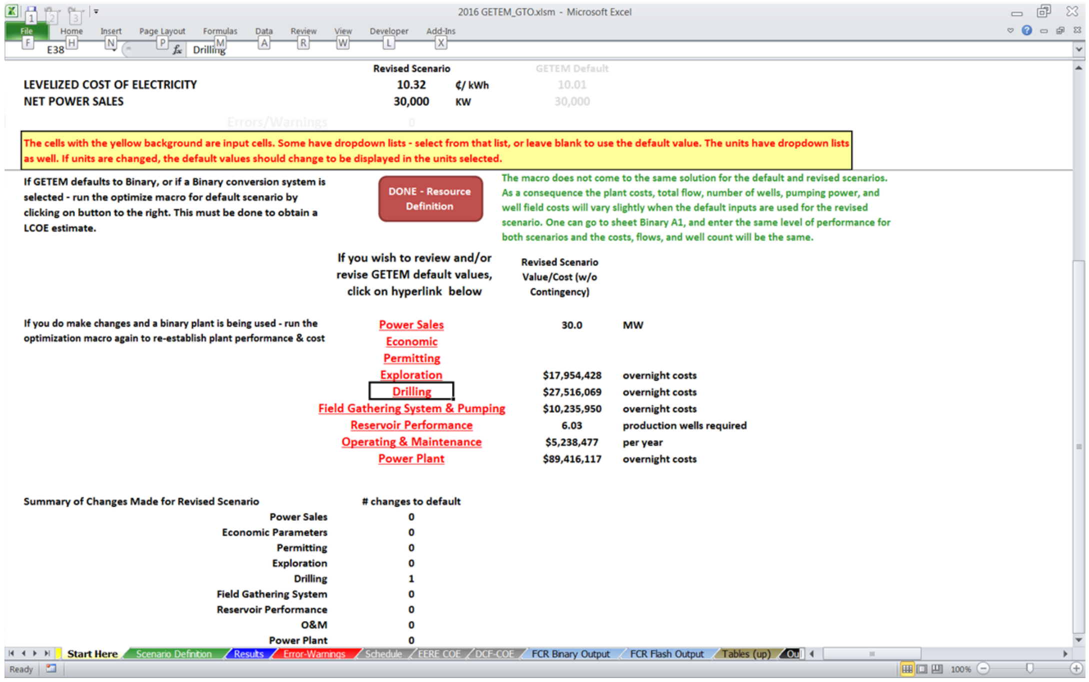


Figure 12. Screenshot of *Start Here* worksheet with updated LCOE (after revising default inputs).

The reasons why the LCOE increased can be found on the summary of the results for both scenarios provided on the *Results* sheet. The results indicate that with the higher injection well flow rates, the geothermal pumping power increased by ~2MW. To provide the specified 30 MW of sales, a larger power plant is needed, along with more geothermal flow and more required production wells (5.77 to 6.03). As postulated, the number of required injection wells decreased (3.56 to 2.33); however, the combined effect is a higher capital cost and a higher LCOE.

1.2.4.2 Scenario Definition. The default values that can be revised are listed on the *Scenario Definition* worksheet. They are grouped by the different project elements that are given on the *Start Here* worksheet. The following discussion reviews default values that can be revised.

Power Sales

There are three inputs under *Power Sales* (shown in Table 3), though only two will be visible to a user at a time.

Table 3. Defaults of the *Power Sales* input parameter.

Power Sales Input Parameter		Hydrothermal Default	EGS Default	Comment
Is project evaluation based on power sales or production well count?		Power Sales	Power Sales	Well count refers to number of successful production wells
Power sales				
binary	T<140°C	10 MW	10 MW	
	140°C<T<175°C	15 MW	15 MW	
	T>175°C	30 MW	25 MW	
flash steam	T<250°C	30 MW	25 MW	
	T≥250°C	40 MW	30MW	
Number of production wells (successful)		NA	NA	Not default

Though the temperature ranges and levels of sales are somewhat arbitrary, they are representative of what one might expect from a resource with three to five producing wells postulated for a Greenfield project. Figure 13 below shows the estimated sales for this number of wells. These estimates are based on the level of performance and flow rate per well taken from the EPRI's report (EPRI 1996).

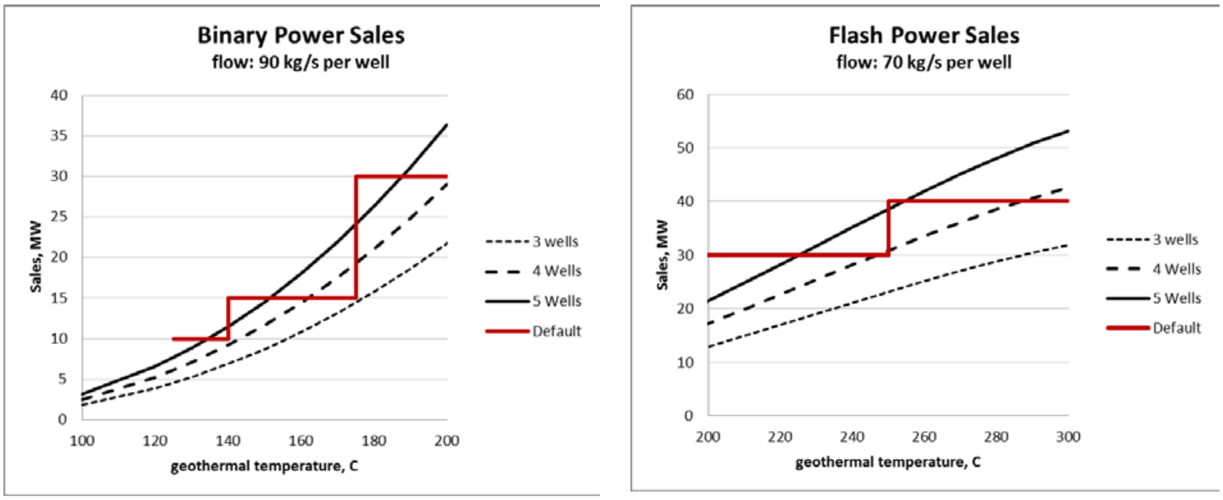


Figure 13. Estimated power sales for three to five wells with a flow of 90 kg/s (left) and 70 kg/s (right).

Economic

There are 19 inputs under *Economic*, shown below in Table 4.

Table 4. Defaults of the *Economic* input parameter.

Economic Input Parameter	Hydrothermal Default	EGS Default	Comment
Year for cost estimates	Current year	Current year	1995 through most current year (PPIs inputted)
Contingency	15%	15%	Applied to all capital costs except drilling costs
Royalty	1.75% through yr 10 3.5% after yr 10	1.75% through yr 10 3.5% after yr 10	BLM royalty rates (2007 Federal Register 43 CFR, Part 3200
Discount rate during operation	7%	7%	EERE recommended value
Effective tax rate	39.2%	39.2%	EERE recommended value
Net capacity factor	95%	95%	Value during initial operation (before resource decline)
Project life	30 yr	25 yr	
Fixed Charge Rate	10.8%	10.8%	Fraction of capital cost recovered annually from Sales
Pre-operation discount rates Exploration Drilling & stimulation Field gathering system Plant construction & startup	 7% 7% 7% 7%	7% 7% 7% 7%	If higher discount rates to be used, they must be a revised input
Re-finance exploration & Drilling after obtaining PPA	No	No	
Project schedule: exploration phase	2.5 yr for Binary 2 yr for Flash	1.5 yr	
Project schedule: drilling phase	2.5 yr	2 yr	
Project schedule: field gathering system	2.5 yr	2 yr	
Project schedule: obtaining PPA and plant design	1 yr	1 yr	
Project schedule: plant construction & startup	2 yr for Binary 1.5 yr for Flash	2 yr for Binary 1.5 yr for Flash	

GETEM allows estimates for any year from 1995 through the most recent year for which the PPIs have been entered. Once the year is selected for which the project is to be evaluated (and costs estimated), GETEM updates its default and estimated costs to the selected year using PPIs. The selected year is also used to determine whether GTO-identified improvements are included. The GTO improvements are included only if the year selected for evaluation is subsequent to the year they occurred. If the improvement has occurred, it is applied to default costs (whether inputted or calculated). Neither the PPIs nor GTO-identified improvements are applied to revised input.

Contingency is applied to all capital costs, exclusive of the costs to drill full-sized wells. The level of contingency is not varied between project phases. Any revised costs, excluding wells costs, should be provided without contingency. The default contingency used can be modified. Contingency is not applied to well costs because the correlations used to determine well costs are based on estimates provided by Sandia National Laboratory (SNL) that included contingency. Revisions to these well costs should include contingency.

The default values for both the discount rate during operation and the effective tax rate were provided by the DOE EERE when incorporating the EERE-recommended methodology for estimating LCOE.

The net capacity factor is the ratio of the estimated annual net power generation from the plant relative to the annual generation if the plant had operated continuously at its design net output for the year. The input value used reflects the impact of varying ambient conditions on output, and the lost generation to both maintenance activities and plant outages. It does not include the effect of declining resource productivity—the effect is accounted for elsewhere in GETEM's calculations. There is further discussion on this metric and the basis for the default value in Appendix A1.

For hydrothermal resources, the project life is based on expected operating life of geothermal plant. There are operating plants in the U.S. with operating lives approaching 30 yrs. The default project life is shorter for EGS resources because of uncertainty in expected reservoir life.

The FCR was used to calculate the LCOE in the original versions of GETEM. Though this method is not used to determine GETEM's reported generation costs, it has been retained in the model and can be used. The FCR is the fraction of the project capital costs that represents the annual cost for capitalized equipment and services. It includes the rate of return on equity and interest on debt, income taxes, property taxes, and insurance. The default value of 10.8% was the rate that was being used when the FCR methodology was last used by GTO to produce GETEM's LCOE estimate (in 2012). Inherent to the FCR methodology for LCOE is a fixed project operating life of 30 years.

The LCOE reported in GETEM is determined using a simplified discounted cash flow methodology recommended by the EERE for analysis of renewable energies. This approach allows one to vary the project operating life, and to assign varying discount rates to each of the different phases of project development. For those phases of a project having higher perceived risk, one can apply a higher discount rate to capital costs incurred during that phase. GETEM uses a single default value of 7% for all project phases. This value is consistent with that used in the EERE's evaluation of other renewables. If these values are revised for the early phases of a project having higher potential risk, there is an option to refinance the costs already incurred, once the PPA is obtained. If this option is selected, the present value of these early costs at the time the PPA is obtained are discounted from that point through startup using the power plant construction discount rate.

The input provided for the duration of the different project phases is used to develop the project schedule. This schedule of project activities and the pre-operation discount rates for the different project phases are used to determine the present value of the pre-operational costs incurred at the start of plant operations. This present value is the basis for the LCOE estimate. There is further discussion as to how this schedule is developed using the input provided (or the default values) in Appendix A2.

The calculation of the LCOE using the discounted cash flow methodology includes a 5-year MACRS (modified accelerated cost recovery) depreciation schedule (Internal Revenue Service 2015). The values used are given below in Table 5.

Table 5. Values for 5-year MACRS depreciation schedule.

Year	Rate
1	205%
2	32%
3	19.25
4	11.52%
5	11.52%
6	5.76%

This deprecation schedule is inherent to the LCOE calculation and cannot be revised. Appendix A3 provides additional discussion as to how GETEM calculates the LCOE.

Permitting

There are five inputs under *Permitting*, which are given below in Table 6.

Table 6. Defaults of the *Permitting* input parameter.

Permitting Input Parameter	Hydrothermal Default	EGS Default	Comment
Permitting duration for exploration & early drilling	1 yr prior to 2013 0.5 yr after 2012	1 yr prior to 2013 0.5 yr after 2012	GTO identified improvement in 2013.
Cost to permit pre-drilling exploration activities	$60K prior to 2013 $50K after 2012	$60K prior to 2013 $50K after 2012	Default costs are in 2012 dollars. GTO identified improvement in 2013.
Cost to permit exploration drilling	$125K	$250K	Default costs are in 2012 dollars.
Permitting duration for plant and completing well field (utilization permit)	1 yr prior to 2013 0.75 yr after 2012	1 yr prior to 2013 0.75 yr after 2012	GTO identified improvement in 2013.
Cost for utilization permit	$1000K	$1000K prior to 2013 $500K after 2012	Default costs are in 2012 dollars. GTO identified improvement in 2013.

The default permitting costs and durations are based on the LCOE analysis team discussions with industry, which is why default costs are referenced to 2012. GTO has identified improvements that have occurred since 2012—reductions in both the time to permit and the cost to obtain a permit. Those improvements are incorporated into GETEM's defaults. They are the default values used in the years after GTO identified the improvements; in previous years, the values defined in 2012 are used. Default costs are adjusted to the year evaluated using the PPI for Legal Services.

Exploration

There are 15 inputs under exploration, shown in Table 7.

Table 7. Defaults of the exploration input parameter.

Exploration Input Parameter	Hydrothermal Default	EGS Default	Comment
Resource to be developed	Greenfield		
Will there be exploration drilling	Yes		
Pre-Drilling			
Number of locations evaluated before drilling	1		
Lump sum costs for pre-drilling exploration activities (per site)	\$500K	\$250K	Default costs are in 2012 dollars
Exploration Drilling			
Number of sites with drilling (small-diameter wells)	1		GETEM default is for site developed
Exploration drilling cost per site for small-diameter wells	\$3000K	\$1500K	Default costs are in 2012 dollars. Small-diameter drilling includes slim-hole, temperature gradient, and core-hole
Number full-sized wells drilled to get each success	2		Default represents a 50% success rate
Number of sites with full-sized wells drilled	1		Default: full-sized wells are drilled only at developed site
Number of full-sized wells drilled at each undeveloped site	0		
Exploration Drilling at Developed Site			
Cost multiplier for full-sized wells ($\geq$1)	1.2		Cost multiplier for full-sized wells ($\geq$1)
Number of successful wells needed to move to drilling phase	2	3	
Number of full-size exploration wells stimulated	0	2 (if either production or injection wells are stimulated) 4 (if both projection and injection wells are stimulated)	GETEM default is one stimulation failure if Exploration wells stimulated
Land area per well	225 acres		
Lease cost	\$30/acre		
Indirect costs during exploration drilling	5% of total drilling/stimulation cost		
Resource potential found	2 X Plant Output + 1 MW		Allows for one replacement of well field
Proportion exploration costs based on resource potential	No		

The exploration input has been changed from previous versions of GETEM which allowed a user to provide more detail on the non-drilling activities, as well as the drilling of smaller-diameter wells. This characterization of exploration was modified as part of the updates made by the LCOE analysis team. During the team's discussions with industry, it was apparent that there was considerable variation in the activities that would occur and what types of wells would be drilled during exploration. Because of this ambiguity, GETEM was revised to characterize both the non-drilling activities and the drilling of small-diameter wells as single lump sum inputs. The default values used for these activities are based on those industry discussions, and are in 2012 dollars (which are adjusted to the year being evaluated using PPIs for *Drilling*, as well as oil and gas [O&G] support activities).

Though GETEM allows for evaluation using a down-select process, with multiple sites having exploration activities prior to discovery of the site eventually developed, the default considers only those exploration costs incurred at the developed site. When multiple sites with exploration activities are evaluated, the costs incurred at all sites are included in the LCOE determination. Well testing costs for undeveloped sites where full-sized wells are drilled are included; these costs are based on the well test cost specified in the input for drilling phase. Full-sized wells drilled at the undeveloped sites are assumed to have the same cost as the full-sized exploration wells drilled at the developed site.

In aligning GETEM with the *Geothermal Handbook* (ESMAP 2012), the exploration and confirmation phases in previous versions were combined into a single phase (exploration). With this change, full-size wells are drilled (and for EGS, stimulated) during the exploration phase. The phase now encompasses the discovery of a commercially viable resource. For hydrothermal resources, successful full-size wells drilled during exploration support production for the power plant once operations begin. With EGS resources, the successful wells drilled during exploration include both production and injection wells (default). If two or more wells are successful in this phase, the well type that is stimulated will have one success. If both production and injection wells are stimulated, there will be an equal number of each that are successful.

GETEM does not have an explicit drilling success rate for the exploration phase. Rather, the input asks how many full-sized wells are required to obtain a successful well during this phase. A drilling success rate is the inverse of this value. GETEM's default is that every other well drilled during exploration is a success (producing a 50% success rate). This default is representative of the early success rates reported in Sanyal's (2012) summary of worldwide survey of drilling success rates, though it should be noted that there is considerable variation in success rate, especially during the early project drilling.

Further discussion of how GETEM determines the count of full-sized wells in the different project phases is provided in Appendix A5; Appendix A6 provides discussion on drilling success rates.

The default for full-sized wells drilled during the exploration phase is a higher cost than wells drilled when completing the well field. This is consistent with Sanyal's (2012) paper, which indicated the drilling rate (m/hr) increased as more wells were drilled. The information in this paper was used to estimate the impact of the drilling rate changes on exploration drilling costs. GETEM's default of a 20% higher drilling cost for full-size wells during exploration are consistent with the estimates made at these lower drilling rates. This evaluation is summarized in Appendix A6.

GETEM estimates the leasing costs based on the inputted cost per acre and estimated acres needed to develop the successful size. It is assumed that the same acreage is required at all sites with drilling activities. The determination of the total leasing costs is summarized in Appendix A4.

The input for resource potential has two uses in GETEM. It determines whether makeup drilling can occur if the resource decline is excessive, and, if so, how many times the well field could be replaced (the GETEM default allows for one replacement). It can also be used in prorating the exploration cost for a project proportionately to the amount of potential used. If this option is used (it is not a default), makeup drilling will not occur to offset the effect of resource decline.

Drilling Activities

There are 24 inputs under *Drilling Activities.*

Table 8. Defaults of the *Drilling Activities* input parameter.

Drilling Input Parameter	Hydrothermal Default	EGS Default	Comment
Drilling success rate	75%	90%	Hydrothermal value is from Sanyal's (2012) paper. When combined with the stimulation success rate used (75%), the value assumed for EGS wells yields a combined success rate approximately equivalent to the hydrothermal default.
Will new wells be required for injection?	Yes		Input can be used when evaluating field expansion rather than Greenfield—or applications with surface discharge of effluent brine.
Do unsuccessful wells supplement injection?	Yes	No	If yes, then well failures during the drilling phase are used to supplement injection.
Relative productivity of unsuccessful wells	0.3	NA	This is used to estimate the injection flow that failed wells will accept.
Ratio of production to injection well flow for successful wells	0.75	0.5	Used in determining geothermal pumping power and number of wells drilled.
Number of spare production wells	0		If spare wells are specified, only their added cost is included. There is no provision to use these wells when determining generation over project life.
Injection well depth	Inputted resource depth		
Well field capacity needed to obtain PPA	60%		Fraction of well field (wells, stimulation, and surface piping) that must be developed to obtain a PPA.
Production well size	*Larger Diameter* for binary *Smaller Diameter* for flash steam		Larger wells needed for pumped wells supporting binary plant.
Injection well size	Larger Diameter for binary Smaller Diameter for flash steam		Unless modified, injection wells default to production well size.
Production interval configuration	Open hole	Liner (perforated or slotted)	Liner assumed for stimulations. Does not impact cost but does impact estimated pressure drop.
Injection interval configuration	Open hole	Liner	Liner assumed for

Table 8. (continued).

Drilling Input Parameter	Hydrothermal Default	EGS Default	Comment
		(perforated or slotted)	stimulations. Does not impact cost but does impact estimated pressure drop.
Production well cost	Cost curves (revised for 2015 and later to reflect increased ROP)		If prior to 2015, cost curves based on SNL's 2010 estimates are used.
Injection well cost	Cost curves (revised for 2015 and later to reflect increased ROP)		If prior to 2015, cost curves based on SNL's 2010 estimates are used.
Are wells stimulated?	No	Yes	Failed hydrothermal wells can be stimulated. Those wells that fail stimulation cannot be used to supplement production/injection.
Which wells are stimulated?	NA	Injection wells	Option to stimulate injection, production, or both.
Well stimulation cost	$2,500K (2012 dollars)		Cost adjusted using PPI for drilling services.
Stimulation success rate	75%		Combined with EGS drilling success rate to produce effective EGS well success approximately equivalent to that used for hydrothermal.
Well testing	$150K (2012 dollars)	$500K (2012 dollars)	Postulate longer test for EGS reservoirs.
How are indirect costs determined?	% of total costs		
% of drilling costs	5%		
Lump sum	No		

With Greenfield developments, one or more successful full-sized wells are drilled during the exploration phase. These successful exploration wells contribute to the required production and injection capacity needed for the facility. The remaining well field capacity is developed in the subsequent drilling phase. The input in this section is the basis for determining how many wells must be drilled in this phase and the associated cost.

The drilling success rate represents the fraction of the wells that are drilled that are successful; there is no specified criteria for success other than successful production wells that provide the specified flow, temperature, and productivity; similarly, all successful injection wells will accept the specified flow and have the same injectivity.

The depiction of hydrothermal scenarios has been revised to allow those wells that are not successful to be used to supplement injection. When utilizing failed wells (now a GETEM default), all failed production and injection wells are used. It is assumed that failed wells lack the necessary productivity or injectivity to be successful; the specified relative productivity of the failed well is used to determine injection flow in that well.

The flow rate for a successful injection well is based on the specified ratio of flow relative to a successful production well. In prior versions of GETEM, the ratio of injection to production wells was specified. This change accommodates the option to use failed wells to supplement injection.

The current version of GETEM also has an option to *not* drill new injection capacity. This is for use in field expansion developments for which existing injection capacity is sufficient to support the new expansion. It can also be used to evaluate projects where brine leaving the plant discharges to the surface (no cost is assigned to this type of brine disposal).

The project schedule is now based on when the PPA is obtained, with the premise that to get a PPA, some percentage of the well field capacity must be developed and confirmed. Well testing and associated costs are incurred prior to the PPA. The fraction of the capacity needed for the PPA is used to establish how many successful wells are required (both production and injection). This count of successful wells required establishes how many are drilled (and for EGS, stimulated) prior to the PPA. These total wells drilled establish costs incurred in the *Drilling* phase prior to and after obtaining the PPA.

A detailed discussion of how GETEM determines the number of wells required and drilled is provided in Appendix A5.

In determining well costs, GETEM utilizes one of two cost correlations depending upon whether the well size is *Larger Diameter* or *Smaller Diameter*. The default is to use the larger-diameter well with binary plants that are assumed to require downhole pumps; these pumps provide the necessary flow rates and maintain the geothermal fluid in the liquid phase. The larger-diameter well configuration assures that the upper casing interval in the well will accommodate the pump. Though EGS resources may have lower flow rates, GETEM still defaults to the larger well size with binary plants in order to accommodate the use of production pumps. The current default is to use the smaller-diameter well size for flash plants, with the expectation that they will not use production pumps. The injection well defaults to the default size for the production well.

GETEM also has input for the configuration of the production and injection intervals (i.e., whether they are open hole or used a perforated or slotted liner). This input does not impact the well cost. It is used to estimate the frictional losses in that portion of the well bore; these losses are used in determining both production and injection pumping power.

Appendix A6 provides information on the basis for the well cost estimates.

EGS resources default wells that are stimulated; this cannot be revised. It is probable that there will be a relationship between the stimulation cost and the performance (thermal, hydraulic, and flow) of the EGS reservoir created. At this time, there is insufficient information to characterize this relationship. A fixed value is used for stimulation on the premise that it will be sufficient to provide the reservoir and well performance specified. The current default used resulted from the LCOE analysis team discussions with industry with respect to a potential stimulation cost.

Similarly, there is insufficient information available to establish values for the success in developing a successful EGS well. The approach assumes a successful EGS well requires both successful drilling and successful stimulation. Current defaults assume that the success rate in drilling an EGS well will be high, with a lower rate for successful stimulation. The combined success rate is approximately equivalent to the default for a successful hydrothermal well, with the expectation that as the technology and expertise develop, the success rate for stimulation will increase.

Field Gathering System (including Geothermal Pumping)

There are 17 inputs under *Field Gathering System & Pumping*, given below in Table 9.

Table 9. Defaults of the *Field Gathering System & Pumping* input parameter.

Field Gathering Input Parameter	Hydrothermal Default	EGS Default	Comment
How are surface equipment costs determined?	Calculated		
Calculation of surface equipment			Used to calculate piping size
Average distance from well to plant	750 m	500 m	
Maximum pressure drop in piping	10 psi Binary 5 psi Flash		
Inputted Cost for surface equipment	NA		Not default
Geothermal pump & driver efficiency	67.5%		Used for both production and injection pumps (combined 75% pump, 90% driver efficiency)
Production pump			
Are production wells pumped	Binary: Yes Flash: No		
Excess pressure at pump suction (also excess at well-head)	50 psi		Pressure above saturation provides NPSH for pump and for pressure drop between well and plant equipment
Diameter of production pump casing	9.625-inch		Casing size delivering flow to surface
Production pump setting depth	Calculated		Any input with EGS resources is ignored
Production pump installation			
Work over rig	$10,000/day (2012 dollars)		
Installation cost	$5/ft setting depth (2012 dollars)		
Casing cost	$44.75/ft (2012 dollars)		
Installed production pump cost	Calculated		Allows pump cost to be revised
Injection pump			
Surface equipment ΔP for binary plant	40 psid		Used to determine injection wellhead pressure with no injection pumping
Excess pressure in injection well	1 psi		Pressure above GETEM's required calculated value
Installed Injection pump cost	Calculated		Allows pump cost to be revised
Other indirect costs	12%		

GETEM determines the cost of the surface equipment based upon its estimate of the pipe size needed for the well flow rate, distance between plant and well, and the maximum pressure drop specified. The surface piping cost is estimated for a production well to the plant, and that cost is applied to all wells used to support the operation of a plant (successful production and injection wells and any wells used to supplement injection). Additional detail is provided in Appendix A7.

Estimates of the geothermal pumping power required are based upon the well depth, the well casing configuration, and the reservoir parameters defined (flow and either productivity or injectivity index.) Pump costs are based upon the horsepower requirements determined. The methodology used in determining the required pumping power; the cost for that pumping is provided in Appendix A8.

Reservoir Performance

There are nine inputs under *Reservoir Performance,* which are listed below in Table 10.

Table 10. Defaults of the *Reservoir Performance* input parameter.

Reservoir Performance Input Parameter	Hydrothermal Default	EGS Default	Comment
Production well flow rate	Binary: 110 kg/s Flash: 80 kg/s	Binary and Flash: 40 kg/s	Lower flow for EGS represents current performance of EGS reservoirs (data very limited).
Hydraulic Performance of Reservoir			
Productivity index	Binary 2,500 lb/hr per psi Flash 2,500 lb/hr per psi		Value used in EPRI's *Next Generation Geothermal Power Plants* study (EPRI 1996). Same values used for both hydrothermal and EGS.
Injectivity index	Same as Productivity Index default		
Thermal Drawdown			
Annual temperature decline rate	Binary 0.5% Flash 0.6%	Binary 0.5% Flash 0.5%	Value impacts the amount of power produced over the life of the plant.
Maximum temperature decline allowed	Value calculated; corresponds to ~ 10% decline in the Carnot efficiency		Triggers the replacement of the well field (if there is sufficient resource potential).
Makeup Water			
Makeup water losses from flash steam plant	No	Yes	Assume that all water losses must be replaced when using an EGS resource.
EGS subsurface water losses	NA	5% of injected flow	Assume that some portion of the injected fluid is not produced with EGS resources.
Makeup water cost	$300/acre-ft	Binary $300/acre-ft Flash $2,000/acre-ft	EGS flash has a higher cost because it is assumed that a higher quality of water will be needed. If quality of water used to replace steam condensate lost is low, the salinity of the produced fluid will increase over time.
Flow into/out of multiple zones in production/injection interval	No	Yes	This calculates the frictional losses in the production and injection intervals assuming that the flow enters or exits along the entire length of the interval.

The inputs provided define the performance of the reservoir. They are used throughout GETEM in defining the size of the plant and well field, the power generation from the project, and the O&M costs for the project. Appendix A9 has more detailed discussion on these inputs and their use.

Characterization of a flash steam plant assumes the use of an evaporative heat rejection system. The source of makeup for the water losses occurring with this type of heat rejection is the steam condensed after it has expanded through the turbine. With hydrothermal resources, the default is to not make up this loss of geothermal fluid (i.e., less fluid is injected than is produced). There is an option for hydrothermal flash scenarios to make up this loss of steam condensate so that total injected flow rate is equal to the total produced flow rate. There is no provision for other options (i.e., injecting more fluid that is produced or making up only a portion of the evaporative cooling system losses). With EGS resources, the amount of fluid injected is equal to the produced flow plus subsurface losses. This is the same for both binary and flash steam plants and cannot be revised.

When the option is selected to depict the flow as entering multiple zones in the production intervals (or leaving multiple zones in an injection interval), the calculation of the friction loss in the well bore is impacted. The default for hydrothermal resources is that flow enters or leaves the well at a single point, with the pressure drop for the interval being determined over its entire length. The default for EGS is that flow enters and leaves uniformly along the entire interval length; this lowers the pressure drop in the interval and reduces the pumping power required. It is thought to be a more likely depiction of the flow for an EGS resource for which the production/injection interval is likely to have multiple stimulation zones.

Operations and Maintenance

There are nine inputs under *Operations & Maintenance*, shown below in Table 11.

Table 11. Defaults of the *Operations & Maintenance* input parameter.

Operations & Maintenance Input Parameter	Hydrothermal Default	EGS Default	Comment
Input or calculate O&M contribution to LCOE?	Calculate		
LCOE contribution for power plant O&M	NA		If LCOE contributions are inputted, provide for both plant and field (which includes production pump maintenance).
LCOE contribution for well field	NA		
Staff labor requirements	Calculate		Estimated based on plant size and type.
Maintenance Costs			
Well field maintenance (% of capital cost)	1.5%		Maintenance cost used is fraction of total capital cost of wells used (includes any stimulation).
Plant maintenance (% of capital cost)	1.8%		Maintenance cost used is fraction of total capital cost.
Production Pump			Maintenance costs determined separately.
Type of production pump	Line shaft		Used only to determine O&M costs.
Pump life	3 year		For line shaft pumps.
Taxes & insurance (% of capital costs)	0.75%		Based only on the costs of the plant and wells used.

GETEM has an option to use inputted values for the O&M contribution to the LCOE. When this option is used, a contribution is provided for both the power plant and the well field. Both inputs are to include any chemical costs associated with the plant and field operation. The inputted field cost contribution is to include the cost for maintenance of the production pumps as well as taxes and insurance. If there are royalties (an input), they are determined separately and added to the inputted value in defining the total O&M contribution for the project.

The labor staff for the project includes staff for the operation of both the plant and well field. The default value used is determined from the plant type and size. When modular units are used, the default uses additional staff.

Annual maintenance costs for the field and plant are determined as a fraction of the initial capital cost. The field maintenance is based on the capital cost of those wells used to support operation of the plant. If the wells were stimulated, those costs are included in the field capital cost used. The field gathering system costs, exclusive of the production pumps, are also included in the field capital costs used to determine the annual maintenance costs for the well field.

The annual maintenance cost contribution for production pumps is determined separately. The type of production pump specified is used to determine the associated maintenance and pump life; the pump type is not used in estimating the capital costs of these pumps.

Annual taxes and insurance are based on the capital costs of all equipment and wells that support the operation of the plant. These are property taxes, not taxes on sales revenues (see Appendix A3 for discussion on the inclusion of tax on sales revenues in the determination of the LCOE).

Specifics on the determination of the O&M costs are provided in Appendix A10.

Power Plant

There are 17 inputs under *Power Plant,* shown below in Table 12.

Table 12. Defaults of the *Power Plant* input parameter.

Power Plant Input Parameter	Hydrothermal Default	EGS Default	Comment
Transmission Line Cost			
Are transmission line costs included?	No		GTO does not include transmission costs when assessing LCOE.
Length of transmission line	0		No transmission line costs are included.
Transmission line cost	$0		No transmission line costs are included.
Plant			
Indirect plant construction costs	12% of direct construction costs		For engineering, home office, and startup.
Binary			
Number of binary modular units used to provide specified sales	1		
Performance metric brine effectiveness	Calculated		Calculated value minimizes LCOE.
Direct construction multiplier	Calculated		Applied to major component costs to determine the direct construction cost.

Table 12. (continued).

Power Plant Input Parameter	Hydrothermal Default	EGS Default	Comment
Air-cooled binary plant cost ($/kW)	Calculated		Calculated value in terms of kW of net plant output—not sales.
Flash Steam			
Number of flash	2		Number of pressures at which steam is flashed and separated—1 or 2.
High-pressure flash-separator pressure	Calculated		Based on DiPippo's equal temperature rule.
Low-pressure flash-separator pressure	Calculated		Based on DiPippo's equal temperature rule.
Type of condenser	Surface		Either surface or direct contact (surface is shell and tube condenser).
Design wet bulb	60°F		Used to estimate plant performance and output from plant over its life.
NCG (non-condensable gas) content	2,000 ppm (mass)		Used to estimate plant performance (steam/power to remove NCGs).
Hydrogen sulfide content	20 ppm (mass)		Used to estimate abatement costs.
Direct construction multiplier	Calculated		Applied to major component costs to determine the direct construction cost.
Flash steam plant cost ($/kW)	Calculated		Calculated value in terms of kW of net plant output—not sales.

Transmission line costs are not included in GTO's assessment of electricity generation costs from geothermal energy. Though there are likely transmission costs associated with a geothermal project, they are not inherent to the geothermal energy source. If transmission costs are to be included, an estimate is made based on the length of the line specified. That estimate can be revised. The basis for the GETEM's estimate is discussed in Appendix A11 (note that the method used differs from that in previous versions of GETEM).

Costs for the power plant are based on the size of the plant needed to provide the specified level of power sales. A default plant type is based on the resource temperature provided. For EGS resources with temperatures of 200°C and lower, a binary plant is the default. If the resource is hydrothermal and the temperature is 200°C or higher, the default is a flash plant. The plant type can be revised on the *Start Here* worksheet. If revised, the default plant type also changes; this is the only instance in which a default input is revised.

The installed cost for both flash steam and binary plants is based on a multiplier that is applied to the total cost of major equipment items estimated for either plant type. For flash plants, the major equipment components estimated are:

- turbine generator
- flash-separator vessels

- cooling tower
- condenser
- pumps
- non-condensable gas removal system
- hydrogen sulfide abatement system

For binary plants, the major equipment components estimated are

- turbine generator
- air-cooled condenser
- geothermal heat exchangers
- working fluid pump

The direct construction multiplier for each plant type includes all materials and remaining equipment, labor and supervision, taxes, and freight. A second multiplier is also applied for the indirect costs associated with the plant installation. These indirect costs include home office, engineering, and plant startup costs. The approach used is analogous to that used in EPRI's report (EPRI 1996).

Flash steam plant performance and cost are determined using the specified inputs.

The binary plant performance metric is the brine effectiveness, or net plant output, per unit mass flow of geothermal fluid. Along with the resource temperature and plant size, this metric is used to determine the binary plant cost. Because this metric affects the amount of geothermal fluid required, it also impacts the number of wells required, the field gathering system cost, and the geothermal pumping power. GETEM includes a macro that varies the brine effectiveness until a LCOE minimum is obtained. If a value is specified for this metric, the macro does not affect the revised scenario LCOE. The macro can be run from the *Start Here* or *Binary A1* worksheets.

The reported costs are in $\$/kW_{net}$, with the net power being the net output from the plant—not power sales. If calculated values for plant cost are revised, the input should also be provided in terms of net plant output.

There is further discussion on GETEM's calculations of both performance and cost for both the flash steam and binary plants provided in Appendix A12.

1.2.4.3 Default Inputs. The default inputs used in GETEM cannot be revised by a public user. The values used for defaults are provided on the *Default Inputs* worksheet. Only GTO can revise these default values on this sheet. Selected defaults can be revised on the *Scenario Definition* worksheet. Those values that can be revised were found to have the larger impacts on the LCOE when considering a probable range of values for the input parameter.

1.3 Model Limitations

GETEM is intended to provide representative generation costs from geothermal energy. While it is amenable to examining costs at specific sites, its estimates are indicative of what costs and performance *could* be. If costs and performance are needed beyond a preliminary assessment, those estimates should be provided by an industry professional.

Estimates are indicative of what could be done with current technology. If one desires to know the impact of a new technology on LCOE, it is necessary that the impact be quantified in terms of how it will impact cost and performance. If GETEM's inputs do not reflect either cost or performance metrics determined, the technology impact cannot be evaluated.

PPIs from the Bureau of Labor Statistics are used to bring model estimates from the year for which they are based to the specified year for evaluation. The PPIs allow the LCOE to be evaluated at any year from 1995 to the most recent year for which the PPIs have been updated. The update of the PPIs is not done automatically.

GETEM has been revised to minimize the input that is required. As a consequence, there are default values that can be changed only by GTO.

When FCR is used to determine an LCOE, it is inherent to the approach that the plant/project life be 30 years. The default method of determining the LCOE (used by the EERE discounted cash flow) allows for a plant life of up to 40 years.

Plants' designs and estimated cost and performance are based on the specified resource temperature and take into account the estimated temperature loss in the production well. There is no provision to consider plants designed for other geothermal temperatures.

Binary plants are air-cooled; flash plants have evaporative heat rejection systems. There is no provision to evaluate water-cooled binary plants or air-cooled flash plants. The cost and performance of these air-cooled binary plants are based on a mean annual air temperature of 10°C (50°F). This air temperature is inherent to the model and cannot be revised for binary plants.

The well costs are based on two common well configurations. The casing designs for these well configurations are inherent to the cost estimates and cannot be revised.

The methods used to determine plant cost and performance are based on specific ranges of resource temperatures and power plant sizes. Though the model will estimate for specified inputs that are outside of those ranges, those estimates should be considered suspect.

Binary plants: 75°−200°C, sizes $\geq$ *3* MW_e
Flash steam plants: 150°−300°C; sizes $\geq$ *10* MW_e

The cost and performance correlations derived for binary plants are based on designs having single vaporizer pressures (i.e., dual boiling cycles were not included). The binary plant designs considered did not include the use of mixed working fluids, but did include designs with vaporization at supercritical pressures.

Plant performance and cost estimates are based on a temperature constraint being imposed on the geothermal fluid leaving the plant. This constraint is based on the solubility of amorphous silica.

It is assumed that the primary material of construction is carbon steel. With the exception of the flash plant condensers, it is assumed that all other components, piping, and casing are fabricated using carbon steel. The estimated costs for surface condensers in flash plants are based on using stainless steel tubes.

The geothermal fluid properties used are derived from curve fits of National Institute of Standards of Technology (NIST) properties for saturated water. The effect of geothermal fluid salinity on properties is not considered. These curve fits provide reasonable approximations of the NIST properties up to ~300°C.

When the resource temperature declines to the maximum value specified, the entire well field is replaced and the costs associated with doing so are incurred at that time. The model does not allow for drilling single wells to offset the temperature decline either by increasing temperature or flow produced to the power plant.

The effect of a declining resource temperature on power production will be dependent upon the power plant design. The method used in GETEM is indicative of how the plant's conversion efficiency and output *could be* impacted. While this efficiency is likely to be impacted differently with each plant design, the depiction of how resource temperature affects performance is representative of what will occur with the constraint that the geothermal flow remains constant.

Validation of model inputs is not completed. This is an ongoing effort and is likely to continue to be so.

Appendix A

GETEM Approach/Calculations

Appendix A

GETEM Approach/Calculations

A1: NET CAPACITY FACTOR

The following provides a brief description of the net capacity factor (NCF) and the basis for the default value used in GETEM for this metric. The NCF in GETEM is

$$net\ capacity\ factor = \frac{actual\ net\ annual\ generation}{annual\ net\ generation\ if\ operating\ at\ design\ net\ output\ continuously}$$

In this determination of the NCF, the net generation is not power sales, nor is it the nameplate generator capacity. It is the generator (nameplate) output less the parasitic load in the plant. Sales equal this net output less the geothermal pumping power. This net output is the basis for the power plant cost in GETEM.

The default value is based on the following assessment of an air-cooled binary plant, with the assumptions that:

- The plant produces 15 MW of power (net)
- The plant has three turbines and three working fluid (WF) pumps
- The condenser has 120 fans
- Five production wells with downhole pumps supply fluid to the plant
- The plant is designed with flexibility similar to the Holt designs for the Mammoth and Steamboat facilities.

The assumptions are used to estimate the effects that maintenance, outages, and the varying ambient conditions have on annual generation (the numerator in the NCF definition).

Maintenance

The effect of production lost to maintenance includes both output lost when maintenance is done without shutting the plant down, as well as when the plant is shut down for maintenance.

Activities Not Requiring Facility Shutdown

The following maintenance in Table A-1 is assumed to be done without a plant shutdown.

Table A-1. Maintenance activities (and related details) that can be done without shutting down a plant.

Activity	Frequency	Duration	Lost Output
Production pump replacement	1.67/yr	2 days	20%
Turbine repair	0.75/yr	3 days	33%
WF pump repair	0.75/yr	2 days	33%
Heat exchanger cleaning/tube plugging	1/yr	1 day	10%
Fan belt replacement	Daily	1 hr	1%
Other	Daily	1 hr	3%

The frequencies given represent a nominal number of times in a year that the activity occurs. It is not indicative of the expected maintenance interval for a specific piece of equipment. For example, the turbines and pumps are expected to require repair every 4 years.

These activities and the frequency, duration, and lost output are based on conversations with operators and limited observations of the operation of these plants. They are also based on a plant being sufficiently flexibility that these activities can be performed while the plant operates. The effect of this maintenance on output is evaluated using the following:

- Assume power output = 1 MW
- Output during normal operations = 1 * # of hours
- Output during maintenance activities = (1- lost output) * # of hours for maintenance
- Output lost during maintenance = lost output * # of hours for maintenance

The lost output over a year using this approach is given below in Table A-2.

Table A-2. Estimated output lost during maintenance activities using the described approach.

Activity	Hrs for Maintenance	Lost Output	Generation Lost (MW-hr)
Production pump replacement	80	20%	16
Turbine repair	54	33%	18
WF pump repair	36	33%	12
Heat exchanger cleaning/tube plugging	24	10%	2.4
Fan belt replacement	365	1%	3.65
Other	365	3%	10.95

The sum of the generation lost over a year for these activities is 63 MW-hr. For a plant running continuously with 1 MW of output, this represents ~0.7% of the annual generation.

Outages

During outages, the plant is shut down with no generation. It is assumed that there would typically be one scheduled outage a year lasting one week (7 days). It is also assumed that there would be 3 days lost per year to unscheduled outages. With these assumptions the plant would be down with no generation a total of 10 days, or 240 hours. This is ~2.7% of the hours available for generation in a year.

Availability Factor

The availability factor is the percentage of time that a plant is available for operation. Based on the effective hours of generation lost during maintenance while the plant is operating and the hours for plant outages, ~303 hours of operation would be lost annually. The plant would be available to operate 8,457 hours in a year, and have an availability factor of ~96.5%.

If the plant would have been shut down for all the maintenance activities, then the plant would have been down for 1,164 hrs (240 + 924). This would have resulted in a plant availability factor of ~86.7%.

Net Capacity Factor

Over the life of the project, a plant's NCF would be based on the plant availability and the impact of the changes to both the ambient temperature and the resource productivity. In GETEM, the effects of changes in the resource productivity are considered separately (see Appendix A9). GETEM's specified NCF includes the effect of plant availability and the ambient temperature on power generation. Because it excludes the effect of a declining resource's productivity, the specified value is effectively what one would expect during the initial operation of the plant.

To estimate the effect of the ambient temperature and plant availability on generation, the annual output from a plant was estimated using the hourly temperature profile at Reno, Nevada over a year. The design output for the plant was based on the mean temperature for the annual profile used for Reno. On an hourly basis, the available energy (exergy) of the geothermal fluid was calculated using the fixed geothermal temperature and the varying ambient temperature. A correlation relating the impact of the ambient temperature on the second law efficiency was used to determine the plant performance for each hour (generally as the ambient temperature deviates from the design temperature, the second law efficiency decreases). Power output at a given hour during the year was the product of the available energy and the conversion efficiency (which are functions of the ambient temperature), an assumed geothermal flow rate, and the plant availability (96.5%). The analysis assumed that there was an operating limit placed on the generator output during the periods with a low ambient temperature (120% of nameplate); if the calculated output exceeded 20% of design, 120% of design was used for that hourly output.

The hourly plant output was totaled for the entire year, and that value was compared to the output that would have occurred if the plant had operated at its design output for 8,760 hours (24 hours per day*365 days). The ratio of the two values is the NCF.

Table A-3 below shows the results for a 15 MW plant operating with different resource temperatures. (Note that geothermal flow rate and conversion efficiency differ for each resource temperature).

Table A-3. Results for a 15 MW plant operating with different resource temperatures.

Resource Temperature	Annual Calculated Output (MW · h)	Annual Output at Design (MW · h)	Net Capacity Factor
100°C	123,776	131,400	94.2%
125°C	124,882	131,400	95%
150°C	125,380	131,400	95.4%
175°C	125,544	131,400	95.5%
100°C	125,556	131,400	95.6%

This evaluation is the basis for the default value of 95% that is used in GETEM for the net capacity factor. Though a similar evaluation has not been made for flash plants, there is an expectation that the value would be similar. Flash plants would not experience the same sensitivity to the ambient temperature because they utilize evaporative heat rejection systems and typically utilize higher temperature resources. Because of the flashing, they could have more generation lost to issues associated with scaling. The assumption is that these two effects negate each other, and the same default is used for both plant types.

The net capacity factor of an operating plant will reflect the effect of a decline in resource productivity. GETEM accounts for this by estimating the effect of a decline in the geothermal fluid temperature on the power generation. This estimate is made for 12 intervals annually for the operating life of the project and incorporated into the LCOE calculation. For a binary plant that experiences a decline of 0.5% annually in the geothermal temperature (from an initial value of 175°C), the power output decreases by ~43% over 30 years. In the EERE methodology, the decrease in output over time is depicted as a declining net capacity factor used in calculating the present value of the power generated over the life of the project. In this scenario, the capacity factor would have effectively decreased from 95% to 54% at the end of 30 years.

A2: SCHEDULE

Based on the input (default or revised) provided, GETEM develops a project schedule that is utilized in determining the present value of a project's pre-operational costs at the start of plant operation. This present value is used in the LCOE calculation that is reported.

The input used:

- Duration of the permitting activity for exploration and early drilling activities
- Duration of exploration phase
- Duration of drilling phase (including stimulation)
- Duration of installing the field gathering system
- Duration of period to establish plant design and finalize the PPA
- Duration of permitting for plant and well field (utilization permit)
- Duration to construct and startup power plant.

Using this input, a project schedule is developed using the following values that are built in to the approach used and cannot be revised.

- Exploration drilling begins 0.5 year after the start of the exploration phase.
- The duration of the drilling activity that occurs after the PPA is obtained is based on the remaining well field capacity that has to be developed to obtain the PPA and the duration of the plant construction; a minimum of 1 month of drilling activity occurs after the PPA is obtained.

  $$Drilling\ after\ PPA = (1 - well\ field\ capacity\ before\ PPA) * plant\ construction$$

  If no well field capacity has to be developed to get the PPA, the completion of the well field drilling will occur concurrently with the plant construction.
- The duration of the drilling activity that occurs before the PPA is the difference between the total time for the drilling phase and the duration of the drilling activity after the PPA is obtained.
- The durations of the well field stimulation and the installation of the field gathering system both before and after the PPA is obtained are determined in the same manner as determining the time for the drilling activities for these periods.
- It is assumed that the costs for engineering the plant design and construction are equally divided before and after the PPA is obtained. Those engineering costs after the PPA is obtained are incurred during the initial half of the period identified for the plant construction and startup.
- The geothermal pump installation is concurrent with the plant construction.
- The installation of transmission lines is concurrent with the plant construction.
- Plant construction and startup activity begins immediately after the PPA is obtained.

Though obtaining the PPA is the focal point in the project schedule, GETEM develops the schedule by working backward from the start of operations through the initial permitting activities for exploration.

With the assumption that plant construction and startup begins immediately after the PPA, this duration establishes when the PPA is obtained relative to the start of operation. The level of field capacity that must be developed prior to obtaining the PPA establishes when the drilling phase begins, which also represents the end of the exploration activities. Immediately prior to the start of the exploration work, the permitting is done for exploration. Some activities are assumed to occur concurrently (e.g., the drilling and installation of the field gathering system needed to obtain the PPA, as well as permitting and completing the well field and installing and operating the power plant).

Figure A-1 below shows this schedule using the model defaults for activity duration for a scenario with a hydrothermal resource and a binary power plant.

year / ***Activity***	**Operation Begins**	-0.5	-1.0	-1.5	-2.0	-2.5	-3.0	-3.5	-4.0	-4.5	-5.0	-5.5	-6.0	-6.5	-7.0	-7.5	-8.0
Operation																	
Power Plant Construction		*****	*****	*****	*****												
Power Plant Design				*****	*****	*****	*****										
Obtain PPA						PPA											
Utilization Permit						*****											
GF Pumps installed		*****	*****	*****	*****												
Surface equipment installed				*****	*****	*****	*****	*****									
Drilling completed				*****	*****	*****	*****	*****									
Exploration Drilling									*****	*****	*****	*****					
Exploration Activities									*****	*****	*****	*****	*****				
Exploration Permit														*****			

Figure A-1. Snapshot of GETEM's project activity schedule using default for hydrothermal resource using a binary power plant.

If the duration of the drilling activity is increased from 2.5 to 3 years with 100% of the well field capacity being developed, the updated schedule in Figure A-2 below reflects the revised input.

year / ***Activity***	**Operation Begins**	-0.5	-1.0	-1.5	-2.0	-2.5	-3.0	-3.5	-4.0	-4.5	-5.0	-5.5	-6.0	-6.5	-7.0	-7.5	-8.0
Operation																	
Power Plant Construction		*****	*****	*****	*****												
Power Plant Design				*****	*****	*****	*****										
Obtain PPA						PPA											
Utilization Permit						*****											
GF Pumps installed		*****	*****	*****	*****												
Surface equipment installed						*****	*****	*****	*****	*****							
Drilling completed						*****	*****	*****	*****	*****	*****						
Exploration Drilling												*****	*****	*****	*****		
Exploration Activities												*****	*****	*****	*****	*****	
Exploration Permit																	*****

Figure A-2. Snapshot of GETEM's project activity schedule with revised input.

Note that the inputs used to determine this schedule are not all in the *economics* input section on the *Scenario Definition* worksheet. The inputs for the time needed for permitting is in the *Permitting* input section of this sheet. The definition of the amount of well field capacity to get a PPA is in the *Drilling Activities* section.

The schedule of pre-operation activities is used to determine the present value of the costs for these project activities at the start of plant operation. This point in time is time zero (0) in GETEM for determining the present value of all project costs and revenues that are used in determining the LCOE, as well as the contributions of different activities to this generation cost. For example, using GETEM's defaults, the overnight exploration costs for the scenario shown above is $607/kW of sales. Using the default schedule and discount rates, the present value of exploration at the beginning of plant operations would be $797/kW. With the increase in the project duration for the revised scenario indicated, the present value increases to $882/kW. This increased the model's LCOE estimate by ~3%.

GETEM also allows one to depict the potential impact of risk on a project, using higher discount rates for those activities with the greatest perceived risk. If the discount rate for the exploration activities was increased from 7% to 20% and all other inputs were kept at the default value, the present value in the previous example would increase from $797/kW to $1,271/kW, resulting in ~6% increase in the estimated LCOE. If the revised schedule discussed above were used with the higher discount rate, the present value would increase to $1,666/kW and result in a ~13% increase in the LCOE.

GETEM does allow for these early project costs to be discounted at a lower rate (the same as that used by the power plant) once the PPA is obtained. With this option, the present value of the exploration costs would be $1,324/kW, which produces a LCOE that is ~9% more than the default estimate.

When GETEM uses the project schedule and discount rates to determine the present value of cost, it assumes that the costs are spread evenly over the activity duration. In addition, the present value of the costs is calculated assuming that they are incurred at the end of a year. For instance, costs that are incurred 6 to 7 years prior to startup are discounted over a 6 year period; those incurred in the year prior to the start of operation are not discounted.

A3: GETEM LCOE CALCULATION

GETEM's calculation of the LCOE for the defined project replicates a discounted cash flow method that is provided by the EERE to GTO as a recommended approach for determining the generation cost for renewables. In this calculation,

$$LCOE = \frac{LCC}{PV(Q)},$$

where

LCC is total lifecycle cost

PV(Q) is present value of annual energy production (Q).

$$LCC = \frac{PV(ICC)\cdot\big(1-\tau\cdot PV(D)\big)+(1-\tau)\cdot PV(O\&M)}{(1-\tau)}$$

where

PV(ICC) is present value of installed capital cost (ICC)

PV(D) is present value of depreciation (D)

PV(O&M) is present value of operation and maintenance cost (O&M)

τ is the effective tax rate (%).

The present values of both costs and power are determined at the start of power generation and sales. This point represents time = "0." Note that this relationship for LCC does not include the royalty payments that are included in GETEM's LCOE estimate.

Capital Costs

The installed capital costs that are included in the LCOE determination are both those occurring prior to the start of operations and those incurred once operation begins. In GETEM, the only capital costs that are incurred after operation are those associated with replacement of the well field that may occur if the decline in resource productivity reaches a maximum threshold.

Those costs that are included in the determination of the pre-operational capital costs include:

- Leasing and permitting for exploration and early drilling activities
- Exploration activities (not associated with drilling)
- Exploration drilling (both small diameter and full-sized wells and any well stimulation)
- Drilling phase prior to obtaining PPA (both drilling and well stimulation)
- Drilling phase after obtaining PPA (both drilling and well stimulation)
- Permitting power plant and completion of well field
- Engineering prior to PPA
- Field gathering system activities prior to PPA
- Field gathering system activities prior to PPA
- Geothermal pump installation
- Plant construction and startup

GETEM assumes that the costs for these activities are spread evenly over the duration identified for each. In calculating the present value of the activity cost, GETEM considers when the costs occur within the project schedule. For example, if the permitting for the plant and well field occurred over a 1-year period from year −3.5 to year −2.5, GETEM would assign half the cost to year −3 and half to year −2.

For each pre-operation activity having assigned costs and schedule, the present value at startup is determined using the following relationship:

$$\mathrm{PV}(\mathrm{OCC}_{activity}) = \sum_{n=0}^{t} \frac{\left(OCC_{activity}\right)_n}{(1+d)^n}$$

where

$OCC_{activity}$ is the overnight capital cost for the activity,

t is the time when the activity begins in the project schedule, and

d is the discount rate.

GETEM allows for evaluation in which all costs incurred before the PPA are subsequently discounted at a lower rate once the PPA is obtained. With this option, the determination of the present value for the activities is adjusted as shown below.

$$\mathrm{PV}(\mathrm{OCC}_{activity})_{PPA} = \sum_{n=0}^{t-t_{PPA}} \frac{\left(OCC_{activity}\right)_n}{(1+d_i)^n}$$

where

$PV(OCC_{activity})_{PPA}$ is the present value of the activity cost at the point in the project schedule when the PPA is obtained,

t_{PPA} is the time in the project schedule when the PPA is obtained, and

d_i is the initial discount rate.

This defines the present value of the project activity at the point in time when the PPA is obtained, at which time these costs are assumed to be re-financed. From this point forward to startup, a lower discount rate is applied (same as power plant) to the PV at this point to determine the activity's present value at startup.

$$\mathrm{PV}(\mathrm{OCC}_{activity}) = \sum_{n=0}^{t_{PPA}} \frac{\mathrm{PV}(\mathrm{OCC}_{activity})_{PPA} + \left(OCC_{activity}\right)_n}{(1+d_2)^n}$$

In this relationship d_2 is the discount rate applied once the PPA is obtained.

The present value of the project at startup (time = 0) is the sum of the present values determined for each of the activities.

$$PV(OCC) = \sum PV(OCC)_{activity}$$

GETEM also uses the PVs for the individual activities to determine the relative contributions of different project phases/activities to the total LCOE determined for the project. This allows GTO to identify which project elements are the major drivers for the LCOE.

The present value of the installed capital cost is the sum of the present values of both overnight capital costs and the replacement capital costs (RCC) incurred over the project life.

$$\mathrm{PV}(\mathrm{ICC}) = PV(OCC) + \sum_{n=1}^{project\ life} \frac{(RCC)_n}{(1+d)^n}$$

In this relationship the discount rate (d) is the specified discount rate for the project once operation begins. It determines present value of the replacement costs, deprecation, O&M costs, and power generation at the start of operation. In GETEM, the only replacement costs considered are those associated with the replacement of the well field. GETEM does not include inflation in its estimates, so the costs used for well field replacement are the overnight costs for the full-size well drilling and field gathering system activities, exclusive of any "failed" wells that are drilled prior to the startup of the facility.

The periodic replacement of the geothermal production pumps during operation of the facility are not considered a replacement capital cost, though they are included in the pre-operational capital costs for the field gathering system. In GETEM, this pump replacement is included as an O&M cost for the facility.

Depreciation

GETEM utilizes a 5-year MACRS depreciation schedule (Internal Revenue Service 2015). The values used are given below in Table A-4.

Table A-4. Five-year MACRS depreciation schedule.

Year	Rate
1	20%
2	32%
3	19.25
4	11.52%
5	11.52%
6	5.76%

GETEM applies this schedule to the present value of the overnight capital costs once operation begins (year 1 as indicated in the table). In the determination of the LCC, the present value of depreciation (PV[D]) is applied to the PV(ICC); the PV(D) used is the present value of the rates in the above schedule for the period shown in the table:

$$PV(D) = \sum_{n=1}^{6} \frac{(depreciation\ rate)_n}{(1+d)^n}$$

Operating and Maintenance (O&M)

In the determination of the LCOE, GETEM assumes that O&M are an annual fixed cost that include:

- Labor
- Plant maintenance
- Well maintenance
- Gathering system maintenance
- Makeup water
- Pump replacement/repair
- Taxes and insurance.

Royalties could also be considered an O&M expense, but GETEM determines that contribution separately when determining the LCOE:

$$\mathrm{PV(O\&M)} = \sum_{n=1}^{project\ life} \frac{(annual\ O\&M\ cost)_n}{(1+d)^n}$$

Power Generation

GETEM's LCOE calculation is based on the present value of the power sales over the life of the project, or the sum of the sales discounted at a specified discount rate over the project life.

$$\mathrm{PV(Q)} = \sum_{n=1}^{project\ life} \frac{(power\ sales)_n}{(1+d)^n}$$

If power sales were constant over the entire life of the project, the determination of their present value would be straightforward. This could occur if the geothermal resource operated with no change in resource productivity over the life of the project. This is unlikely to occur as nearly all geothermal resources experience some productivity decline that is manifested as a decreasing fluid temperature or flow rate. A review of production data from binary plants indicates that the geothermal temperatures have decreased since the beginning of operation. Most of these plants also experience some change in flow rate over their life, with flow generally increasing as operators attempt to maintain power sales. The relative magnitude of these increases in flow varies from facility to facility, as well as with time at a given facility.

GETEM estimates the impact of declining productivity on sales based on a temperature decline with time, with the flow assumed constant. The approach used is not amenable to considering both flow and temperature, and because decreasing temperature is more likely to occur, it is used to characterize the effect of declining resource productivity on power sales.

The impact of a declining resource temperature on power sales is estimated over the life of the project. Plant output is determined for 12 equal increments for each year of the project life; this calculation is based on the geothermal temperature at a point in time, an assumed ambient temperature (10°C or 50°F for binary plants), and the initial performance of the plant. The two temperatures (source and sink) determine the available energy (specific exergy), which is the ideal work that could be done by a conversion system using reversible processes. No actual conversion system can achieve this ideal performance. The fraction of this ideal work that is converted to useful work (power) is the second law efficiency of the conversion system or power plant.

The second law efficiency is also impacted by the resource temperature decline. This efficiency will be at its maximum when operating near the design geothermal and ambient conditions. As the resource temperature declines, so will this conversion efficiency. GETEM's estimates of net output from the power plant include this effect on efficiency.

Power sales is the difference between the plant output and the geothermal pumping power. In GETEM it is assumed that the geothermal pumping power does not change from what is determined at startup (i.e., the geothermal flow remains constant, the hydraulic performance of the reservoir does not change, and the effect of temperature decline on density heads in both the production and injection well negate each other). The effect of temperature decline on power is illustrated in Figure A-3 below. Note that this is an example based on a postulated initial plant performance and geothermal pumping power.

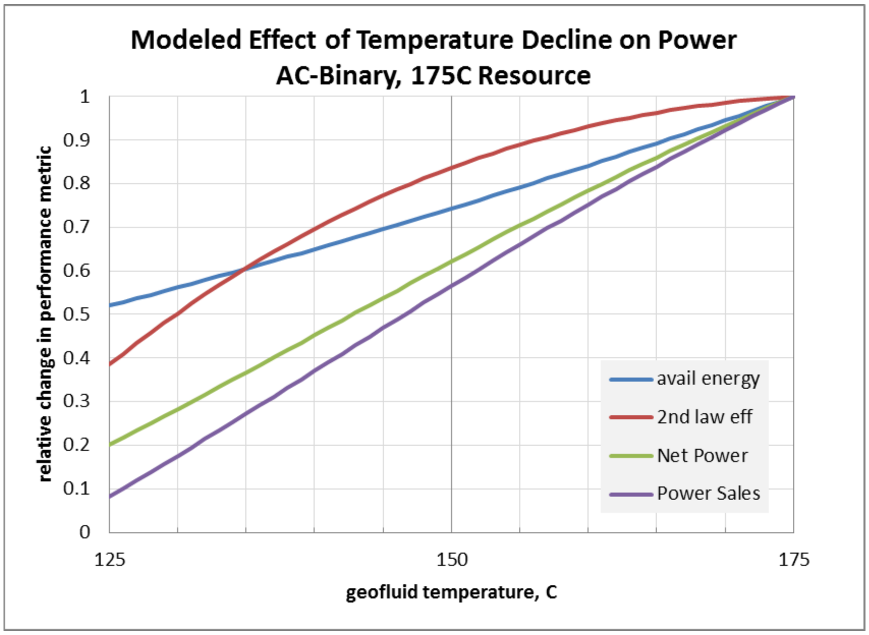


Figure A-3. The effect of temperature decline on power.

The decline in the available energy shown in this figure is indicative of the level of decline that will be experienced under ideal conditions with no geothermal pumping. Because it is improbable that one could increase the conversion efficiency as the temperature declines, sustaining power generation would require an increased flow rate. (Note that increasing flow would likely further lower the second law conversion efficiency.)

Again, GETEM's methodology does not allow for increasing flow rate. To represent an operator's use of new wells to supplement production or replace wells to mitigate the effect on sales, GETEM assumes that there is a maximum allowable temperature decline, after which the entire well field is replaced, and the production temperature and plant output return to their initial design values.

For the 175°C resource temperature in the above figure, GETEM's default for the maximum allowable temperature decline is slightly less than 25°C. The maximum decline is based on a curve fit of the end of project life temperature taken from the EPRI's report (EPRI 1996). This decline corresponds to a ~10% decrease in the Carnot efficiency for all resource temperatures. Using the GETEM default, the well field depicted in this figure would be replaced once the temperature had declined to ~150°C; at this point power sales would have decreased by ~44%.

GETEM uses an annual decline rate to characterize the temperature decline of the geothermal resource. Figure A-4 depicts the decline rate that would trigger a well field replacement. These decline rates preclude the replacement of the well field during the last 5 years of the project life—this exclusion is built into GETEM and effectively allows for a higher decline rate before triggering the replacement of the well field.

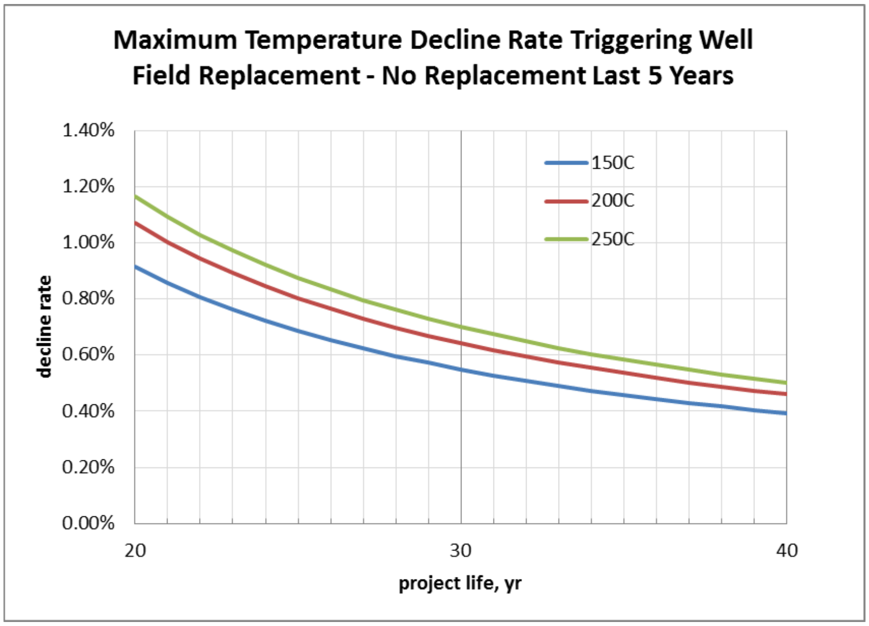


Figure A-4. Rate of annual temperature decline that would trigger well field replacement.

For GETEM's default of a 30-year project life, if a 200°C resource temperature declined at a rate higher than 0.65%, the well field would be replaced before the plant reached 25 years of operation. This decline rate produces a 1.3°C (2.3°F) temperature decline the first year, with slightly less in the subsequent years. With no replacement, by the end of the project (30 years), the 200°C resource would have declined in temperature to ~165°C with the 0.65% annual decline rate.

Though GETEM calculates the effect of temperature decline on power output on a monthly basis, the present value calculation of the power generated uses the power output at the end of a year to determine the annual generation for that year. For a representative temperature decline rate, the annual generation based on the plant's year-end power output is 0.5 to 1.2% lower than when determined on a monthly basis, with the difference increasing each year throughout the life of the project. The total generation over a typical 30-year project will be ~1% higher if generation is established on a monthly rather than a year-end basis; the impact on LCOE would be similar. Though conservative, the use of year-end power to determine annual generation is consistent with the EERE methodology provided.

The EERE methodology for determining LCOE depicts the impact of a declining resource temperature as a decline in the capacity factor with time. A capacity factor is the ratio of the actual generation over a year to what would have been produced if the unit operated continuously throughout the year at a "design" value. NCF is a GETEM input. The basis of the power in this value is the net output from the plant (sales plus geothermal pumping power). The value includes the effects of maintenance, outages, and the ambient temperature on annual generation. For the depiction of the effect of temperature decline on power sales, it is assumed that the capacity factor based on power sales and that based on net plant output will behave similarly. With this assumption, GETEM's NCF input is used in the EERE methodology as the initial (design) capacity factor based on power sales.

The degradation in the capacity factor is determined using the following relationship:

$$\delta_{CF} = 1 - e^{c} \text{ , where}$$

$$c = \frac{\ln\left(\frac{sales_{@\,t_r}}{sales_{design}}\right)}{t_r}$$

and δ_{CF} is the annual decline rate for the capacity factor (CF)

$sales_t$ is the power sales at time t

$sales_{design}$ is the design power sales.

t_r is either the project life, or the time at which the 1st well field replacement occurs.

The power sales at any point in time (n) is

$$power\ sales_n = power\ sales_{design} * CF_{design} * (1 - \delta_{CF})^n$$

The present value of the power sales for the project is (with no well field replacement)

$$\text{PV(Q)} = power\ sales_{design} * CF_{design} \sum_{n=1}^{project\ life} \frac{(1 - \delta_{CF})^n}{(1 + d)^n}$$

With well field replacement, the present value of the sales is

$$PV(Q) = power\ sales_{design} * CF_{design} \frac{\sum_{n=1}^{t_r}(1 - \delta_{cf})^n + \sum_{n=1+t_r}^{2*t_r}(1 - \delta_{cf})^{n-t_r} + \sum_{n=1+2*t_r}^{3*t_r}(1 - \delta_{FD})^{n-2*t_r} + \cdots}{\sum_{n=1}^{project\ life}(1 + d_r)^n}$$

In this relationship, t_r is the time when well field replacement first occurs, and d_r is the discount rate used for costs and revenues once operation begins. In GETEM, the well field will continue to be replaced, provided sufficient resource potential was found during exploration to allow for re-drilling the well field one or more times, and the replacement does not occur in the last 5 years of the project life.

With a high rate of temperature decline and insufficient resource potential for well field makeup, at some point the power output will go to zero. At this point an *Error/Warnings* message will be received that power output is zero before the end of project life. Depending upon the scenario being evaluated, the model may or may not continue to estimate the present value of subsequent power generation (which will be negative). If it does, it will continue to do so through the end of the inputted project life. Similarly, it will continue to include in the present value of O&M costs through the end of the project. This leads to an overestimate of both the costs and power generation (and an underestimate of royalties) used to determine the LCOE. As a consequence, once this error occurs, the estimates produced by GETEM are not valid.

These issues do not occur when using the DCF on the *DCF-COE* worksheet. However, when using the DCF, the model cannot solve for the level of plant performance that minimizes the LCOE. If one uses the DCF to determine the LCOE, one should first optimize binary performance to minimize the LCOE determined using the EERE methodology based on declining capacity factor and then determine the LCOE with the DCF. This will define a plant performance metric (brine effectiveness) that can be manually adjusted until the LCOE is a minimum.

The issues associated with the power going to zero before the end of the project life are also relevant to the FCR method. This methodology correctly accounts for the sales and revenues going to zero, but a 30-year project life is inherent to the fixed charge rate method in GETEM.

Royalties

The default for the annual royalty payments on LCOE is based on the BLM schedule for royalties, in which 1.75% of the annual revenues are paid through the first 10 years of operation, and 3.5% of annual revenues are paid after 10 years.

In determining the contribution of royalty payments to the LCOE, GETEM first determines the present value of the power generation in the initial period. The method used is the same as discussed in the previous section for determining the present value of power generation for the project life. Once that value is determined, it is used with the present value of all power generation to determine the levelized value of the royalties, which is representative of the present value of the royalties relative to the present value of the total revenues.

$$levelized\ royalties = \frac{\left[RR_{initial} \times PV\ Power_{initial} + RR_{final} \times \left(PV\ Power_{life} - PV\ Power_{initial}\right)\right]}{PV\ Power_{life}}$$

where

$RR_{initial}$ is the royalty rate (1.75%) for the initial period (10 years)

$PV\ Power_{initial}$ is the present value of the power generated during the initial period

RR_{final} is the royalty rate (3.5%) after the initial period

$PV\ Power_{life}$ is the present value of the power generated during the initial period (*PV[Q],* the value discussed in the previous section)

Royalties are based on the final LCOE and the annual power production. The next section describes how this final determination of LCOE is accomplished.

LCOE Determination

In the calculation of the LCOE, GETEM uses the levelized royalties, levelized capital costs and levelized O&M costs as depicted here:

$$LCOE = \frac{(levelized\ capital\ cost + levelized\ O\&M\ cost)}{(1 - levelized\ royalties)}$$

The determination of the levelized royalties is discussed in the previous section. The levelized capital costs include the initial project capital costs and any subsequent replacement capital costs (*PV[ICC]* in the previous discussion).

$$levelized\ capital\ costs = \frac{PV(ICC) \times \frac{(1 - \tau \times PV(depreciation))}{(1 - \tau)}}{PV(Q)}$$

The levelized O&M cost is determined using the following relationship:

$$levelized\ O\&M\ costs = \frac{PV(O\&M) \times \frac{((1 + d)^{project\ life} - 1)}{(d \times (1 + d)^{project\ life})}}{PV(Q)}$$

GETEM determines LCOE contributions from the following:

Capital costs:

- Exploration
- Drilling
- Field gathering system
- Stimulation
- Power plant
- Permitting
- Makeup drilling.

Operating costs:

- O&M labor
- Maintenance for plant
- Maintenance for well field and reservoir
- Maintenance for gathering system
- Water makeup
- Production pump maintenance
- Taxes and insurance
- Royalties.

The contribution from each of the capital cost contributors is:

$$LCOE_{capital\ cost} = \frac{PV(capital\ cost\ contribution) \times \frac{(1 - \tau \times PV(depreciation))}{(1 - \tau)}}{PV(Q)}$$

The contribution of each of the operating costs (excluding royalties) is:

$$LCOE_{O\&M} = \frac{PV(annual\ O\&M\ contribution) \times \frac{((1 + d)^{project\ life} - 1)}{(d \times (1 + d)^{project\ life})}}{PV(Q)}$$

The royalty contribution is:

$$LCOE_{royalty} = LCOE_{total} \times \frac{\left[RR_{initial} \times PV\ Power_{initial} + RR_{final} \times \left(PV\ Power_{life} - PV\ Power_{initial}\right)\right]}{PV\ Power_{life}}$$

Other LCOE Methods

The reported LCOE is determined using the EERE methodology described. There are two alternative calculations of LCOE within GETEM that have been alluded to. One is a simple discounted cash flow method and the second is based on a fixed charge rate.

Discounted Cash Flow

This calculation is on the *DCF-COE* worksheet. The capital costs and operating costs used in this calculation are the same as those utilized in the EERE methodology. The calculation differs from that used in the EERE methodology in how power sales are determined. This approach uses the calculated year-end power output, while the EERE methodology bases power sales on the effect of a declining capacity factor. This worksheet has two macros: one each for the default and revised scenarios. Each macro varies the cost of electricity until the present values of all costs are equivalent to the present value of all revenues (a "0" cash flow). If there is no resource temperature decline, the cost of electricity determined should be equivalent to that determined using the EERE method.

If this method is used with binary plants, it is recommended that the default values be used for the revised scenario to establish a representative level for the plant performance. Revisions can be made to the inputs, and the macros run on this sheet to determine a cost of electricity. The optimal plant performance/minimum LCOE can iteratively be found by adjusting the brine effectiveness for the binary plant (*Scenario Definition—Power Plant*) and running the macros on the *DCF-COE* worksheet until the LCOE for the revised scenario is minimized.

Fixed Charge Rate

The calculation of the LCOE using the FCR was used in the original versions of GETEM. Though this calculation is also not reported, it has been retained in the model and can be used. The FCR is the fraction of the project capital costs that represents the annual cost for capitalized equipment and services. It includes the rate of return on equity and interest on debt, income taxes, property taxes, and insurance.

The default value of 10.8% was the rate last used when the FCR methodology was the basis for GETEM's LCOE estimate in 2012. This was the value used in the EIA NEMS runs for the *Annual Energy Outlook* report (EIA 2015). A fixed project operating life of 30 years is inherent to GETEM's FCR methodology for LCOE.

The LCOE for either the default or revised scenario is determined using the methodology described below.

$$activity\ overnight\ capital\ cost_{per\ kW} = \frac{overnight\ capital\ cost_{activity}}{design\ sales_{kW}}$$

$$activity\ annual\ cost_{per\ kW} = activity\ overnight\ capital\ cost_{per\ kW} \times FCR$$

$$capital\ LCOE\ contribution_{activity} = \frac{activity\ annual\ cost_{per\ kW}}{effective\ capacity\ factor \times 8{,}760\ hr/yr}$$

$$effective\ capacity\ factor = capacity\ factor_{design} \times relative\ generation$$

$$relative\ generation = \frac{\sum \frac{annual\ sales}{(1 + discount\ rate)^n}}{\sum \frac{design\ sales}{(1 + discount\ rate)^n}}$$

In this relationship, the annual sales are based on the estimated monthly outputs that take into account any resource temperature decline. The design sales is the specified or calculated initial sales. Both of these sales values are determined and summed monthly over the project life (n). The capacity $factor_{design}$ is the inputted net capacity factor.

The effective annual power generation is based on this effective capacity factor. This annual generation is used with the estimated O&M costs to determine the O&M contribution for each activity to the total LCOE.

$$effective\ annual\ power\ generation = effecive\ net\ capacity\ factor \times design\ sales_{kW} \times 8{,}760\ hr/yr$$

$$O\&M\ LCOE\ contribution_{activity} = \frac{annual\ O\&M\ cost_{activity}}{effective\ annual\ power\ generation}$$

$$LCOE\ contribution_{capital\ and\ O\&M} = \sum capital\ LCOE\ contribution_{activity} + \sum O\&M\ LCOE\ contribution_{activity}$$

Royalties are based on sales revenues. To determine royalties, an effective royalty rate is determined.

$$effective\ royalty = \frac{\left(royalty_{through\ 10\ yr} \times 10 + royalty_{after\ 10} \times \{project\ life - 10\}\right)}{project\ life} \times relative\ generation$$

$$royalties = LCOE\ contribution_{capital\ and\ O\&M} \times \frac{effective\ royalty}{(1 - effective\ royalty)}$$

$$LCOE_{FCR} = LCOE\ contribution_{capital\ and\ O\&M} + royalties$$

A4: LEASING

The leasing costs in GETEM are based the leasing cost determined for the developed site and the number of sites having drilling activities. The cost for leasing at the developed site is determined from the number of full-sized wells that are drilled during all project activities, the number of acres per full-size well, and the cost per acre for the lease. GETEM calculates the number of full-sized wells based on the project size, plant performance, flow per well, and drilling success rates for the project phases having drilling activities. The well count includes both successful and unsuccessful (failed) wells, but does not include wells drilled after the operation begins; it is assumed that the acreage allotted per well will be sufficient to account for drilling of makeup/replacement wells.

$$lease\ cost_{developed\ site} = \#full\ size\ wells \times acres_{per\ well} \times cost_{acre\ leased}$$

The total leasing cost used in determining the LCOE is the product of the lease cost for the developed size and the number of sites that have drilling activities, where the number of sites is the larger of the number of sites with small-diameter drilling and the number with full-size well drilling.

$$total\ leasing\ cost = lease\ cost_{developed\ site}(\#sites\ with\ drilling)$$

The acres required per full-size well and the cost per acre are both GETEM inputs. A review of historical BLM lease sales provides a perspective of the default inputs. A presentation made by the BLM at the 2014 Geothermal Resources Council (GRC) meeting indicates that between June of 2007 and September of 2014, 379 leases were sold with a total of 1,048,237 acres, or ~2,765 acres per lease (Hagerty 2014). The figure below summarizes the reported lease sales occurring during this period.

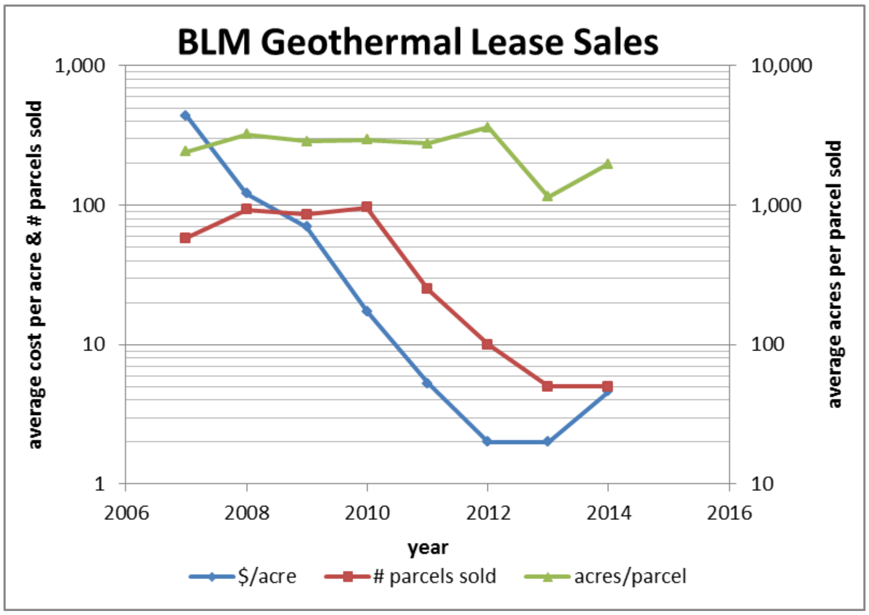


Figure A-5. BLM lease sales from June 2007 to September 2014.

Sanyal's (2012) paper used a criteria of 3 MW capacity to define a successful well. Using this as a metric for establishing the acreage per well, a 20 MW binary plant would require 6.67 successful production wells. With a default flow ratio of 0.75 (production to injection flow), five successful injection wells would be needed. With an overall drilling success rate of 68% (from Sanyal's paper), ~17.2 wells would be drilled. For the average lease size of 2,765 acres, this would result in ~160 acres required per full-size well.

GETEM typically calculates a plant performance that results in a well capacity greater than 3 MW per well; for binary plants, the value is typically in the range of 4 to 5 MW capacity per well. Using a value of 4 MW capacity per well, the well count would be ~12.9 wells, or ~215 acres per full-size well for the average parcel size leased.

GETEM defaults to an average spacing of 0.75 km between well and plant. Assuming the wells were laid out with a similar spacing between wells, there would be ~110 acres per well. With this spacing, GETEM's default value of 225 acres per well allows the well field to be replaced with this idealized well configuration.

The default lease cost of $30 per acre was established by the LCOE analysis team review of GETEM inputs in 2012, and was based on successful bids for the 2009 lease sale in Nevada. Though recent successful bids are lower, the default is considered representative of a cost during a period when geothermal energy production is expanding.

A5: WELL COUNT

Hydrothermal Resources

Exploration Phase

- There is no specific well count for slim holes, core holes, and/or temperature gradient holes. The costs for those wells/holes are included in the lump sum value inputted.
- The default scenario assumes full-sized wells are drilled only at the site developed, but it can be revised to include drilling of full-sized wells at more than one site. If this is done, the user must identify how many wells are drilled at each unsuccessful site. (The default is 0 because the default only considers costs for the successful site.) Though costs for full-sized wells that are drilled at sites not developed may be included in the total exploration phase costs, these wells do not support the subsequent operation of a power plant.
- The model assumes that two successful full-sized wells are drilled during the exploration phase (at the final site developed). The model also assumes that to get a successful well, two wells must be drilled (based on a success rate of 50%). The default is that 2 × 2 or four full-sized wells are drilled during the exploration phase at the final site. Successful full-size exploration wells support plant operation.

Drilling Phase

- The model assumes that drilling occurs only at the final site.
- Successful wells from the exploration phase are assumed to be production wells.
- If the user defines the project based on the number of production wells used, the number of successful production wells drilled during this phase is that defined number less the number of successful exploration wells.
- If the user defines the project based on power sales, the number of production wells required or needed is determined with the following relationships:

$$total\ GF\ flow_{req} = \frac{power\ sales}{[brine\ effectiveness - GF\ pumping]}$$

In this relationship, the brine effectiveness and GF pumping are in units of power per unit mass flow. The brine effectiveness is the numerator in the second law efficiency, and is the parameter that GETEM varies when determining the minimum LCOE. The GF pumping is based on the production and injection well flow rates, well depth, well injectivity or productivity, and the default casing design for each well type.

$$production\ wells_{req} = \frac{total\ GF\ flow_{req}}{flow_{prod\ well}}$$

The flow per production well is a model input that can be revised.

The number of production wells required is determined in this manner regardless of the type of resource or conversion system. Note that the number of wells required is based on the assumption that all wells have the same performance—temperature, flow rate, and productivity index.

- The number of injection wells required is also based on the total GF flow. A model variable is the ratio of the production well flow relative to the injection well flow.

$$flow_{inject\ well} = \frac{flow_{prod\ well}}{ratio\ of\ production\ to\ injection\ well\ flow}$$

$$injection\ wells_{req} = \frac{total\ GF\ flow_{injected}}{flow_{inject\ well}}$$

With flash power plants, the total flow injected will be less than the total flow produced, unless the water loss in the evaporative cooling towers is made up. Making up this loss is an option for hydrothermal resources, for which sufficient makeup is provided that injected flow and produced flow are equivalent.

These relationships are the basis for determining the number of injection wells required when failed wells are not used to supplement injection flow. Whether or not to use failed wells is a model variable for hydrothermal resources. This model variable is not used for EGS or hydrothermal resources for which wells are stimulated. If failed wells are used, then all failed production and injection wells are used. The method for determining the number of "successful" injection wells is described below.

- *Use of Failed Wells:*
  - Failed wells are assumed to have a productivity relative to successful wells (a value less than 1). This is a model input that can be revised. The injectivity index of a failed well (II_{fail_well}) is

$$II_{fail\_well} = \ Productivity\ Index_{successful\_well} \times relative\ productivity$$

  - The injection flow taken by a failed production well is estimated as:

$$flow_{fail\_PW} = \left[P_{well-head} + \Delta P_{inj\_pump} + \rho_{inj}(depth_{PW}) - \Delta P_{friction} - P_{hydrostatic}\right] \times II_{fail\_well}$$

This calculation is based upon the injection pump head determined for the flow in a successful injection well. In this relationship, GETEM estimates the friction loss ($\Delta P_{friction}$) based on that determined for a successful well, with the assumption that the flow will be proportional to the relative productivity specified.

  - A similar approach is used to determine the flow in the failed injection wells that are used to supplement total injection. The primary difference is that instead of the production well depth, the injection well depth is used to determine flow rate in those wells.
  - The number of injection wells that are drilled is based on the total flow to the injection wells:

$$total\ flow_{IW} = total\ GF\ flow - \#PW_{fail}\left(flow_{fail\_PW}\right)$$
$$total\ flow_{IW} = \#IW_{suc}\left(flow_{successful\_IW}\right) + \#IW_{fail}\left(flow_{fail\_iW}\right)$$

  - These relationships can be used to determine the number of successful injection wells that must be drilled based on the inputted drilling success rate (DSR):

$$\#IW_{suc} = \#IW_{drilled}(DSR)$$
$$\#IW_{fail} = \#IW_{drilled}(1 - DSR)$$
$$\#IW_{fail} = \#IW_{suc}\left(\frac{1}{DSR} - 1\right)$$
$$\#PW_{fail} = \#PW_{suc}\left(\frac{1}{DSR} - 1\right)$$
$$total\ flow_{IW} = \#IW_{suc}\left[flow_{suc\_IW} + flow_{fail\_IW}\left(\frac{1}{DSR} - 1\right)\right]$$
$$\#IW_{suc} = \frac{total\ flow_{IW}}{\left[flow_{suc\_IW} + flow_{fail\_IW}\left(\frac{1}{DSR} - 1\right)\right]}$$
$$\#IW_{suc} = \frac{\left[total\ GF\ flow - \#PW_{fail}\left(flow_{fail\_PW}\right)\right]}{\left[flow_{suc\_IW} + flow_{fail\_IW}\left(\frac{1}{DSR} - 1\right)\right]}$$

In this relationship, the number of failed production wells is based on the number of production wells needed or required ($\#PW_{suc}$).

- *Total Wells Drilled During Drilling Phase—Hydrothermal Resources*
  - The total number of production wells drilled is calculated as follows:

$$production\ wells_{drilled} = \frac{\left[production\ wells_{req} - \#\ full\ size\ expl\ well_{suc}\right]}{DSR}$$

$$injection\ wells_{drilled} = \frac{[injection\ wells_{req}]}{DSR}$$

where

$$production\ wells_{req} = \frac{total\ GF\ flow_{req}}{flow_{prod\ well}}$$

If failed wells are not used to supplement injection, the number of injection wells required is

$$injection\ wells_{req} = \frac{total\ GF\ flow_{req}}{flow_{inject\ well}}$$

or when failed wells are used, the number of successful injection wells needed is

$$\#IW_{suc} = \frac{[total\ GF\ flow - \#PW_{fail}(flow_{fail\_PW})]}{\left[flow_{suc\_IW} + flow_{fail\_IW}\left(\frac{1}{DSR} - 1\right)\right]}$$

where $\#IW_{suc} = injection\ wells_{req}$

The use of all failed wells to support the operation of the power plant is the current GETEM default for hydrothermal resources. This version of GETEM differs from previous versions in that the user defines the ratio of production to injection flow rate for successful wells. Previously, a user inputted the ratio of injection to production wells, and that ratio was used to determine the number of injection wells drilled. If one opts not to use failed wells to supplement injection, the model's calculations will reflect the previous approach used—unless the hydrothermal wells are stimulated.

The current version of GETEM has modified the use of stimulation for hydrothermal resources. If wells are stimulated with hydrothermal resources, then only failed wells in the *Drilling* phase are stimulated. If stimulation is specified, it can be applied to failed production, failed injection, or both well types. A stimulation success rate (SSR) is applied to reflect that not all stimulations are successful. A successfully stimulated well will perform equivalent to a successfully drilled well. When wells are stimulated, the option to used failed wells to supplement injection is not used, regardless of the input provided. This occurs even for those failed wells that are not stimulated (if one opts to only stimulate either production or injection wells). It also applies to wells that are unsuccessfully stimulated.

- *Hydrothermal Well Stimulation*
  - If production wells are stimulated, the number of production wells drilled during the *Drilling* phase can be determined using the following. (Note in these equations that *SSR* is the stimulation success rate.)

$$\#PW_{suc} = production\ well_{req} - \#full\ size\ Expl\ well_{suc}$$
$$\#PW_{suc} = \#PW_{drilled} - \#PW_{fail\_drill\&Stim}$$
$$\#PW_{drilled} = \#PW_{suc\_drill} + \#PW_{fail\_drill}$$
$$\#PW_{suc\_drill} = \#PW_{drilled} \times DSR$$
$$\#PW_{fail\_drill} = \#PW_{drilled} \times (1 - DSR)$$
$$\#PW_{fail\_drill\&Stim} = (1 - SSR)\#PW_{fail\_drill}$$
$$\#PW_{suc} = \#PW_{suc\_drill} + \#PW_{fail\_drill} - \#PW_{fail\ \_drill\&stim}$$
$$\#PW_{suc} = \#PW_{drilled} \times DSR + \#PW_{drilled}(1 - DSR) - \#PW_{drilled}(1 - SSR)(1 - DSR)$$
$$\#PW_{suc} = \#PW_{drilled}[DSR + (1 - DSR) - (1 - SSR)(1 - DSR)]$$
$$\#PW_{suc} = \#PW_{drilled}[1 - (1 - SSR)(1 - DSR)]$$
$$\#PW_{drilled} = \frac{\#PW_{suc}}{[1 - (1 - SSR)(1 - DSR)]}$$
$$\#PW_{drilled} = \frac{[production\ well_{req} - \#full\ size\ Expl\ well_{suc}]}{[1 - (1 - SSR)(1 - DSR)]}$$

- A similar approach is used to determine the number of injection wells drilled when they are stimulated. In this case, the number of successful wells used for injection is 0. The number of injection wells required is:

$$injection\ wells_{req} = \frac{total\ GF\ flow_{req}}{flow_{inject\ well}}$$

$$\#IW_{drilled} = \frac{\left[\ injection\ well_{req}\right]}{[1-(1-SSR)(1-DSR)]}$$

- The model default for the drilling success rate is 75% during the *Drilling* phase. Some of the values the model uses as defaults are best estimates. For hydrothermal resources these values include:
  - Productivity of unsuccessful wells relative to successful wells: **0.30**
  - SSR: **75%**
  - Stimulation costs: **$2,500,000** (This value is from the work done in 2012. It is brought forward in time using the Bureau of Labor Statistics PPI for drilling services.)

EGS Resources

Exploration Phase

An approach similar to that used for hydrothermal resources is used to determine the exploration well count with EGS resources. The number of wells drilled to get a successful well is still an input used to determine the total number of wells drilled. For an EGS resource, it is assumed that one of the wells drilled is also successfully stimulated; this assumption is inherent to the model and cannot be revised. GETEM has input for the number of wells to be stimulated during the exploration phase; the stimulation success rate during exploration is effectively this inverse of this input.

GETEM's default is that three wells from the exploration phase will be considered successful and utilized to support the operation of the power plant; one of these wells will be successfully stimulated. GETEM's EGS defaults are that there will be one stimulation failure, that two wells are drilled to get a successful well, and that injection wells will be stimulated.

Using these defaults to achieve three successful wells, six full-sized well are drilled. One of the three unsuccessful wells will be stimulated, as well as one of the successful wells. Of the three successful wells, one will be an injection well (stimulated) and the other two will be production wells.

As with hydrothermal resources, the costs to drill both the unsuccessful and successful full-sized wells are included in the exploration costs. With EGS resources, exploration costs also include the stimulation costs for the number of wells specified as being stimulated. If one opts to stimulate only production wells, then one of the three successful wells will be a production well (successfully stimulated), and the remainder will be injection wells. If both wells are stimulated, then all successful wells from the exploration phase will be successfully stimulated, with the total evenly split between production and injection. In this case, though multiple wells may be successfully stimulated, the default assumption remains that one stimulation is a failure.

If the stimulated wells are injection wells, and if the number of successful exploration wells is two or more, then

- # exploration wells used for injection = 1
- # exploration wells used for production = # successful exploration wells – 1

If 1 $\leq$ # successful exploration wells < 2, then

- # exploration wells used for injection = 1
- # exploration wells used for production = # successful exploration wells – 1

If # successful exploration wells < 1, then

- # exploration wells used for injection = # successful exploration wells
- # exploration wells used for production = 0

If the stimulated wells are production wells, and if the number of successful exploration wells is two or more, then

- # exploration wells used for injection = # successful exploration wells – 1
- # exploration wells used for production = 1

If 1 $\leq$ # successful exploration wells < 2, then

- # exploration wells used for injection = # successful exploration wells – 1
- # exploration wells used for production = 1

If # successful exploration wells < 1, then

- # exploration wells used for injection = 0
- # exploration wells used for production = # successful exploration wells

If both production and injection wells are stimulated, then

- ½ of the successful # exploration wells are used for injection
- ½ of the successful # exploration wells are used for production

Drilling Phase

The determination of the number of successful production and injection wells required is the same as that used for the hydrothermal resource:

$$production\ wells_{req} = \frac{total\ GF\ flow_{req}}{flow_{prod\ well}}$$

$$injection\ wells_{req} = \frac{total\ GF\ flow_{injected}}{flow_{inject\ well}}$$

With EGS resources, the amount of fluid injected is equal to the total flow produced plus makeup for any specified subsurface losses. It is assumed that failed EGS wells will not be used to supplement injection, and it is assumed that if a well stimulation fails, the well will not be used.

GETEM allows for the injection wells only to be stimulated (model default), the production wells only to be stimulated, or for both injection and production wells to be stimulated. In determining how many wells are drilled and stimulated in this phase, it is necessary to account for those successful wells that are drilled in the exploration phase.

- *Injection Well Only Stimulated:*
  - The number of production wells drilled in this phase is based on the drilling success rate (DSR), the number of successful exploration wells that are considered to be production wells, and the number of production wells required.

$$production\ wells_{drilled} = \frac{\left[production\ wells_{req} - \#Exp\ wells_{suc\_prod\ well}\right]}{DSR}$$

  - The number of injection wells drilled is based on the DSR, the SSR, the number of successful exploration wells considered to be injection wells, and the number of injection wells required.

$$injection\ wells_{drilled} = \frac{\left[injection\ wells_{req} - \#Exp\ wells_{suc\_inject\ well}\right]}{[DSR \times SSR]}$$

  - The number of injection wells stimulated is based on the following:

$$injection\ wells_{stim} = injection\ wells_{drilled} \times DSR$$

$$injection\ wells_{suc\_stim} = injection\ wells_{stim} \times SSR = \left[injection\ wells_{req} - \#Exp\ wells_{suc\_inject\ well}\right]$$

The number of wells stimulated ($injection\ wells_{stim}$) is the basis for the estimated stimulation cost.

- *Production Well Only Stimulated:*
  - The number of production wells drilled in this phase is based on the DSR, the SSR, the number of successful exploration wells that are considered to be production wells, and the number of production wells required.

$$production\ wells_{drilled} = \frac{[production\ wells_{req} - \#Exp\ wells_{suc\_prod\ well}]}{[DSR \times SSR]}$$

  - The number of production wells stimulated is based on the following:

$$production\ wells_{stim} = production\ wells_{drilled} \times DSR$$
$$production\ wells_{suc\_stim} = production\ wells_{stim} \times SSR = [production\ wells_{req} - \#Exp\ wells_{suc\_inject\ well}]$$

The number of wells stimulated ($produciton\ wells_{stim}$) is the basis for the estimated stimulation cost.

  - The number of injection wells drilled is based on the DSR, the number of successful exploration wells considered to be injection wells, and the number of injection wells required.

$$injection\ wells_{drilled} = \frac{[injection\ wells_{req} - \#Exp\ wells_{suc\_inject\ well}]}{DSR}$$

- *Both Injection and Production Well Stimulated:*
  - The number of injection wells drilled is based on the DSR, the SSR, the number of successful exploration wells considered to be injection wells, and the number of injection wells required.

$$injection\ wells_{drilled} = \frac{[injection\ wells_{req} - \#Exp\ wells_{suc\_inject\ well}]}{[DSR \times SSR]}$$

  - The number of injection wells stimulated is based on the following:

$$injection\ wells_{stim} = injection\ wells_{drilled} \times DSR$$

  - The number of production wells drilled in this phase is based on the DSR, the SSR, the number of successful exploration wells that are considered to be production wells, and the number of production wells required.

$$production\ wells_{drilled} = \frac{[production\ wells_{req} - \#Exp\ wells_{suc\_prod\ well}]}{[DSR \times SSR]}$$

  - The number of production wells stimulated is based on the following:

$$production\ wells_{stim} = production\ wells_{drilled} \times DSR$$

  - The total number of wells stimulated is calculated as:

$$\#\ wells\ stimulated = injection\ wells_{stim} + production\ wells_{stim}$$
$$\#\ wells\ stimulated = [injection\ wells_{drilled} + production\ wells_{drilled}] * DSR$$

- The default values used for determining the well count for EGS resources are best estimates. These values include:
  - Drilling success rate: **90%**
  - Stimulation success rate: **75%**
  - Stimulation costs: **$2,500,000** (This value is from the work done in 2012. It is brought forward in time using the Bureau of Labor Statistics PPI for drilling services.)
  - Production well flow rate: **40 kg/s**
  - Ratio of production to injection well flow rate: **0.5**

Drilling Before/After PPA

The number of wells that must be drilled before the PPA is obtained is determined based on the number of wells required and the specified well field capacity that needs to be demonstrated in order to obtain the PPA. The well field capacity is the fraction of the required injection and production wells needed for the facility to operate. For example, if 60% of the well field capacity is required to obtain a PPA, and 10 successful production and five successful injection wells will be needed to operate at full capacity, then six successful production wells and three successful injection wells must be developed prior to obtaining the PPA. This would include any stimulation needed for a well to be considered successful.

Determining how many wells are drilled and stimulated prior to obtaining the PPA uses the same approach as is used in determining how many are drilled and stimulated for the entire project. The number of wells drilled and stimulated during the exploration phase remains the same. The number required for the *Drilling* phase is changed from that needed to support the project to that needed to get the PPA. Once the number drilled and stimulated are determined, the drilling and stimulation after the PPA is the difference between the values determined for the entire project and those required to obtain the PPA.

A6: DRILLING

While the power plant may represent a larger monetary investment in the development of a geothermal project, the uncertainty in drilling successful wells can put an entire project at risk. To acknowledge the potential for drilling failure, GETEM utilizes a drilling success rate to establish how many of the wells drilled will support the operation of the power plant, and includes the costs of unsuccessful wells when determining the power generation cost. If the down-select process is utilized (it is not the GETEM default) for the project evaluation, the generation cost will be included on all drilling costs, including those at sites drilled but not developed.

Exploration Drilling: Full-Size Wells

The GETEM default during the Exploration phase is that every other full-size well drilled is successful, or a 50% success rate. This drilling activity is effectively the confirmation phase in prior versions of GETEM. The prior default used for confirmation drilling success rate was 60% at the developed site, suggesting that the current default may be conservative. Figure 17 from Sanyal's (2012) paper indicates there is considerable variation in this success rate. This figure provides drilling success curves for 12 well fields where 24 or more wells were drilled.

GETEM's current default is that there are four to six full- size wells drilled during the exploration phase. Interpreting the success rate from Figure 17 in Sanyal's (2012) paper is difficult for this number of wells because of the overlap of curves. An initial assessment of this data indicated a median after drilling both four and six wells to be ~50%, with the average being higher (~55% after four wells, and ~60% after six wells).

This paper indicates there is a learning curve in terms of the drilling rate (m/hr) as more wells are drilled. In the example given, the drilling rate increased from ~46 to 90% from the exploration phase to later in the field development (see Figure 19 of Sanyal's [2012] paper), or, conversely, the rates given indicate they were 32 to 47% lower during the early drilling activities. Well costs were estimated using these lower drilling rates, or rates of penetration (ROP), using the SNL cost models. The well costs during exploration were higher as indicted in Figure A-6 below.

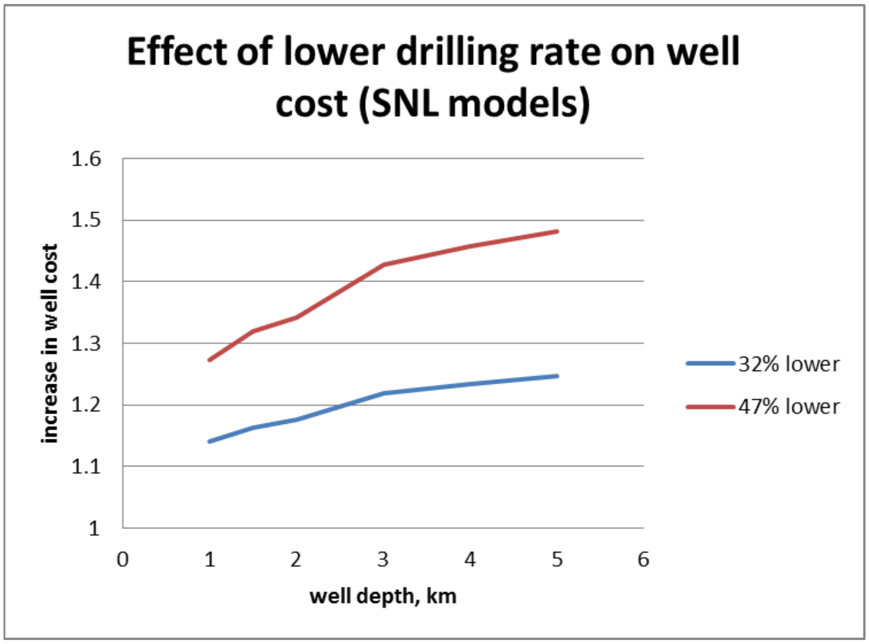


Figure A-6. The effect of lower drilling rates on well cost based on the SNL models.

The GETEM default for the effect of this learning curve on well costs is 1.2, which represents the impact of the 32% lower ROP. Using this data to establish a relative cost is speculative because total well counts determined for the scenarios considered in GETEM are generally lower than those in Sanyal's (2012) paper; however, this work does indicate that there is a learning curve and that as more wells are drilled, the drilling rate (m/hr) increases. Wells initially drilled should be expected to cost more, and though the amount of data is limited, the GETEM default of 20% higher is not improbable.

Drilling Phase

Success Rate

Sanyal's (2012) paper indicates that in the survey of drilling success rates, the average value of a project was ~68%. As apparent in Figure 17 of Sanyal's paper, there is considerable variation in this success rate (33 to 100%), with the prevalent range between 60 and 80%.

There are questions that arise when reviewing this paper and integrating the information presented into GETEM:

- The criteria for success is a minimum of 3 MW capacity, which implies this is the success for a production well. The success criteria for injection wells is not specified, and as such, it is not known if injection wells are included in the assessment.
- Presumably there is drilling of makeup wells included in the data presented. It is not clear if the wells are considered successful if they are taken out of service and replaced with a makeup well.
- Most of the well fields that are included in the survey have more wells drilled than would typically be drilled in a scenario evaluated by GTO.
- It is unclear whether some of these projects received any government support. Unless the wells are inexpensive to drill and/or extremely productive, it would be difficult for a geothermal project in the U.S. to be economically competitive with success rates of 50% or less for the entire well field.

Though there are questions, the information in the paper provides a basis for establishing default inputs for GETEM. To do so, the following assumptions are made:

- The drilling success rates presented are for both production and injection wells.
- Wells that are used to support plant operation are successful even if they are eventually replaced with makeup wells.
- The differences in project size are ignored, as is the potential that some may have received government support.

One difference between GETEM's depiction of drilling success and that described in Sanyal's (2012) paper is that GETEM uses two drilling success rates—one for the early project activities and one for the final drilling phase to complete the well field. The average value reported by Sanyal is based on all drilling activities. Figure A-7 below illustrates GETEM's effective success rate for the entire project that is analogous to the average for the well field. On the left is the effective rate with the current GETEM default of 50% during exploration; on the right is for a 60% success rate during exploration. The blue shaded box is the range of likely values from Sanyal's paper. The number of wells required is typical of the scenarios being evaluated in GETEM by GTO.

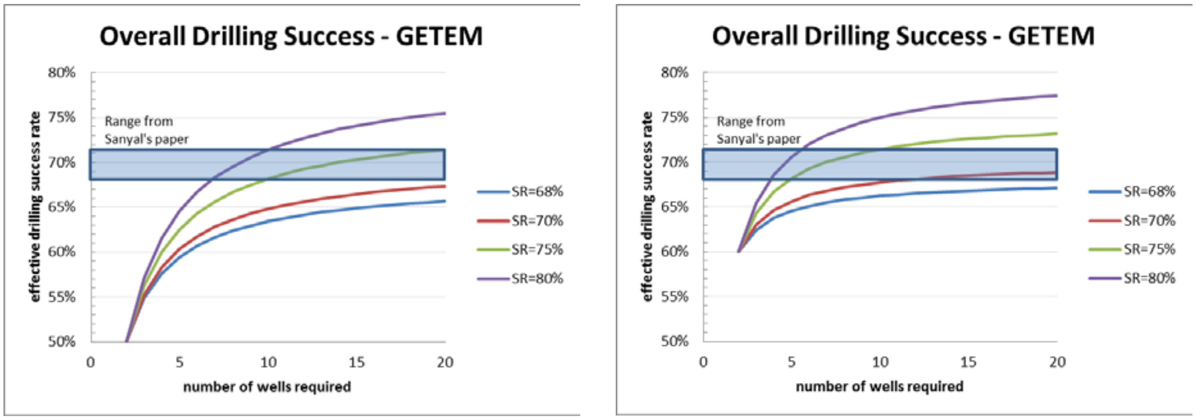


Figure A-7. The effect of exploration drilling success rate (50% on left and 60% on right) on GETEM's effective overall drilling success rate.

Using the 68% value from Sanyal's (2012) paper as the default yields a lower effective drilling success rate, regardless of which success rate is used during the exploration phase. With a default drilling success rate of 50% during the exploration phase, a 75% success rate during the final drilling phase yields an overall success rate that is within the range given in Sanyal's paper.

With EGS resources, two success rates are used during the drilling phase: one for drilling the well and one for stimulating the well. GETEM's defaults are established such that the combination of these two rates produces an overall success rate similar to that used for the hydrothermal resource. The success rate defaults used for GETEM are a 90% success rate in drilling the wells, and a 75% success rate for stimulating. Using these rates for a binary EGS scenario (GTO scenario C), if only injection wells are stimulated the overall success rate is ~73%, while if only production wells are stimulated the overall success rate is 68%. These overall rates are consistent with the target range shown in Figure A-7.

Drilling Cost

The drilling costs in GETEM were derived from well costs provided by SNL to the LCOE analysis team. The SNL estimates were provided at 1 km intervals for depths from 1 to 6 km. Though 6 km is an unlikely depth for hydrothermal resources, EGS resources at this depth could be developed and are included in GTO's assessment of generation costs from EGS. The number of casing/liner intervals in the wells are shown in Figure A-8 below for different well depths. All casing interval are cemented in place. Liners are hung from the casing or liner interval immediately above it, and except for the bottom interval, liners are also cemented in place.

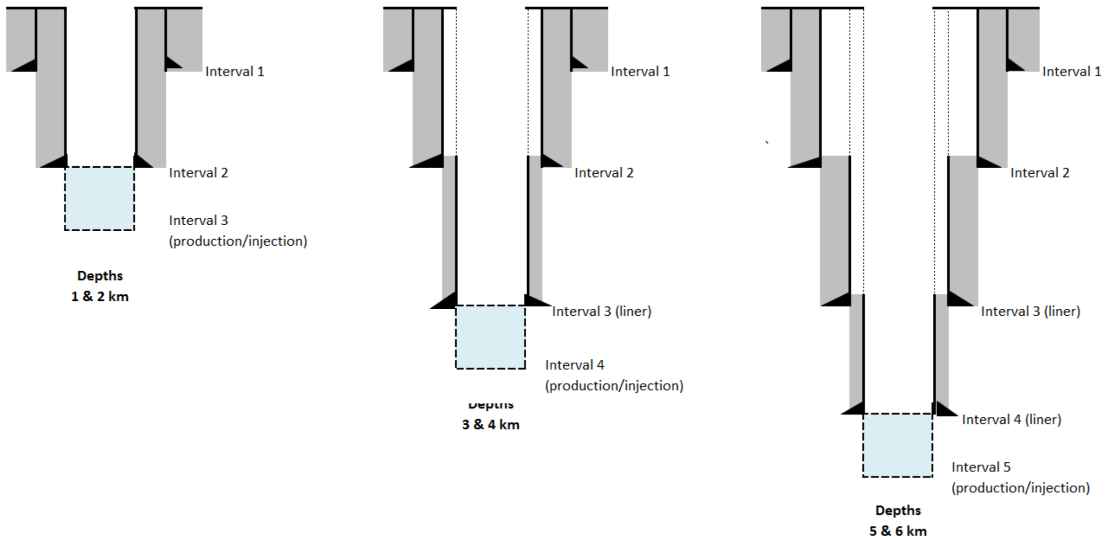


Figure A-8. Casing designs for different well depths.

At each depth, four casing configurations were considered based on different diameters and completions for the production/injection intervals. This interval could be either open hole or have a slotted liner, and for each of these options this bottom interval could have two different diameters. The larger-diameter well has a bottom interval of 12.25 inches if open, and 9.625 inches if a slotted liner. The smaller-diameter well has an 8.5-inch diameter in the interval if open, and 7-inch diameter if a liner. The diameters of the casing in the casing and/or liner intervals above the bottom interval are dependent upon which of the two bottom hole sizes are selected, as well as the depth of the well.

While the casing configuration for a well is not used in GETEM as the basis for the well cost, within GETEM there is a methodology analogous to that used by SNL. Though the methodology does produce an estimated drilling cost, its primary purpose is to provide a casing design for the well that is used to estimate the pressure loss in the production and injection wells, and in estimating the temperature loss as fluid flows up the production well. A summary of the casing configuration used for both the production and injection well is provided on both the *OUT* and the *Drilling Costs* worksheets.

Because there was minimal difference in the cost between wells with the different bottom hole configurations, GETEM's correlation for well costs is based on depth and the well size—either larger diameter or smaller diameter wells. These correlations are curve fits of the SNL cost estimates for each diameter as a function of depth.

$$cost_{LD\ well} = 0.033 * depth^2 + 350 * depth + 290000$$
$$cost_{SD\ well} = 0.033 * depth^2 + 150 * depth + 290000$$

The SNL cost estimates included a 15% contingency; that contingency is retained in these correlations.

These changes to GETEM's well costs were made as part of the LCOE analysis team's efforts to update and improve the model inputs. Before adopting the SNL estimates as the basis for GETEM's well costs, a review was made of geothermal drilling costs found in the literature and obtained during the team's discussions with members of the geothermal industry. These costs as a function of depth are summarized in Figure A-9 below.

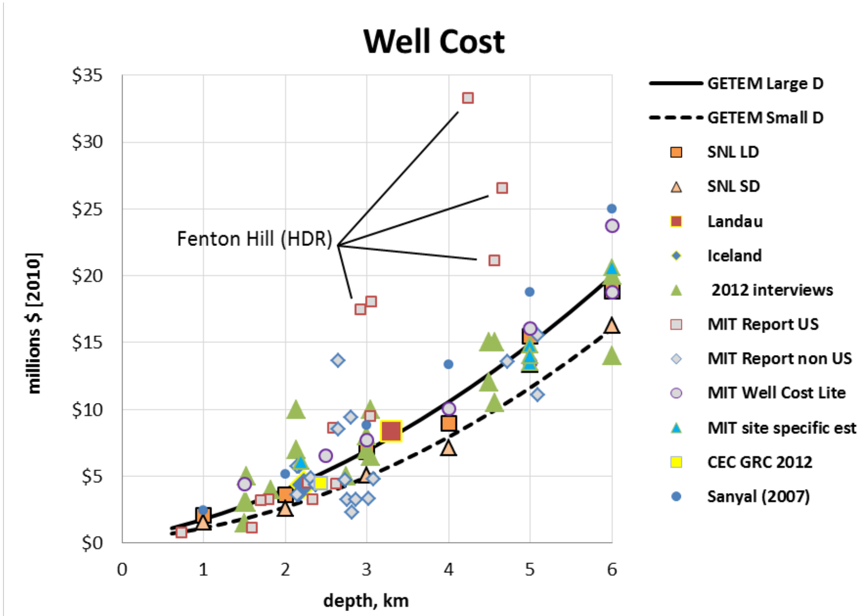


Figure A-9. Summary of drilling costs collected from literature and geothermal industry interviews.

For the costs from the different sources to be comparable to the GETEM correlations it was necessary to bring those costs to an equivalent point in time. That point was 2010, which is the basis of the costs provided by SNL and the basis for the GETEM correlations. This was accomplished using the PPI for drilling oil and gas wells, obtained from the U.S. Bureau of Labor Statistics. With this adjustment to the costs from the different sources, the cost correlations based on the SNL estimates (also shown in this figure) were deemed representative of geothermal drilling costs and the correlations incorporated into GETEM.

Since GETEM was originally developed in 2004–2006, there has been considerable variation in drilling costs. That volatility is captured in GETEM using the PPI for oil and gas well drilling. When a year is selected for analysis, this PPI is applied to the year 2010 costs determined using one of the two cost correlations. With the PPI applied, the drilling cost is representative of costs in the year for which the analysis is being made. Figure A-10 shows how the PPI used has varied with time. It illustrates how drilling costs have varied over relatively short periods of time, and serves to emphasize the importance of updating GETEM's PPIs before estimating current costs.

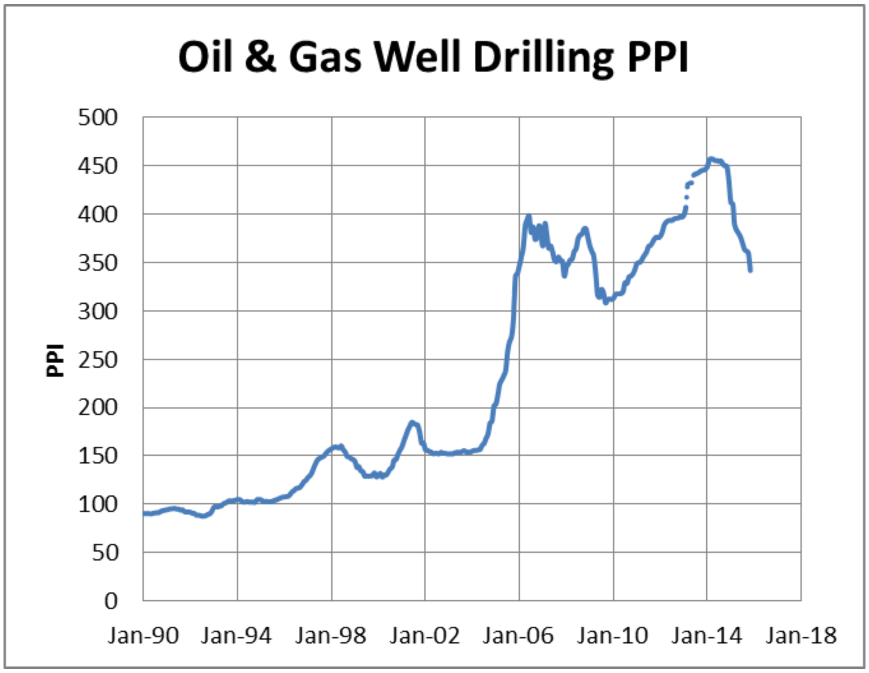


Figure A-10. Time variation of the producer price index for drilling oil and gas wells.

A7: SURFACE EQUIPMENT

GETEM determines the surface equipment costs using a correlation that estimates the cost of surface piping per foot based on the piping diameter. This correlation was developed using cost estimates from Icarus Process Evaluator (IPE) for standard schedule piping varying in size from 4 to 36 inches. Estimates included expansion loops at 300 ft intervals, a check valve and butterfly valve, one tee, pipe supports, and insulation. All estimates were made for 1,000-ft pipe lengths. Those estimates are shown below in Figure A-11 along with the polynomial curve fit of the estimates.

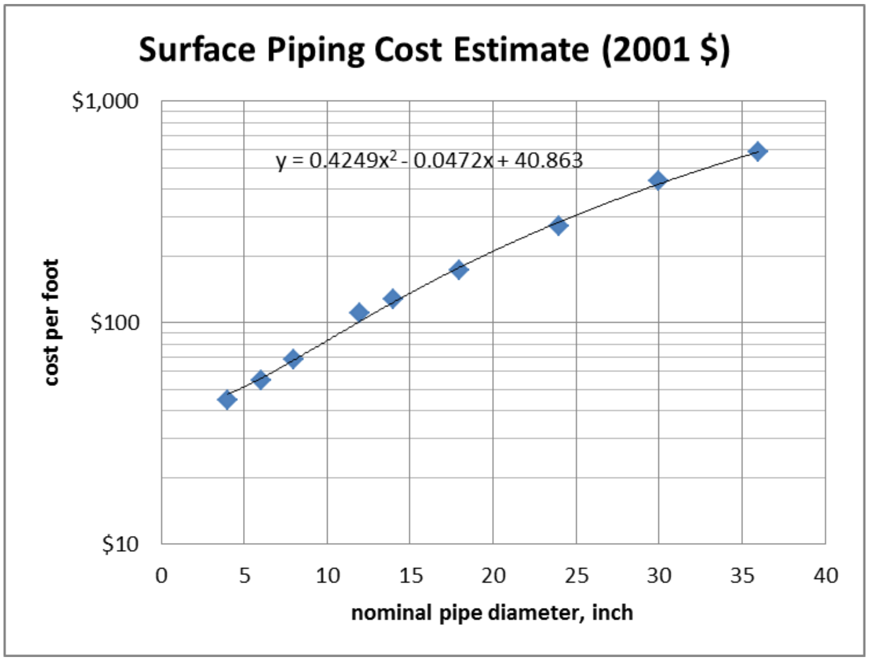


Figure A-11. Surface equipment piping system cost estimates.

These estimates are in 2001 dollars. GETEM brings these costs to the year being evaluated using the PPI for steel pipe.

The average distance from the well to the power plant is specified, along with the well flow and the allowable pressure drop in the piping. This information is used in a six-step iteration to estimate the minimum piping diameter needed. The assumptions inherent to this sizing include:

- An expansion loop every 300 ft
- A pipe surface roughness of 0.00015 ft
- An initial assumption that an 8-inch diameter pipe is used

First iteration:

- Calculate area and fluid velocity based on well flow and pipe size
- Determine Reynolds number
- Calculate Darcy friction factor using Serghide's solution
- Sum the friction resistances: K for expansion loop elbows and f(L/D) for pipe
- Multiply the sum of the resistances by the 1st diameter—gives an effective f(L); use this value to estimate a new pipe diameter. The head loss in the piping can be expressed as:

$$head_{target} = \frac{(f(L))_{effective}}{D^*} x \frac{V^2}{2(g)}$$

In this expression $head_{target}$ is head loss corresponding to the allowable ΔP. Velocity (V) and $f(L)_{effective}$ are determined using the initial diameter. This relationship is used to solve for the diameter (D^*) that would be needed with this velocity and frictional losses to produce the targeted head loss.

$$D^* = \frac{(f(L))_{effective}}{head_{target}} x \frac{V^2}{2(g)}$$

This diameter is used to estimate the next diameter used in the iteration process. In the above relationship V∝ D^2; the diameter that would give the velocity and frictional losses that would result in the targeted head loss is

$$D_2 = D_1 \times \left(\frac{D^*}{D_1}\right)^{0.25}$$

This new diameter is used to repeat the above calculations to determine the velocity, friction losses, the diameter needed to produce the targeted head loss, and the new diameter. After the initial estimate of 8 inches, this iteration is repeated five more times. At that point, the estimated diameter converging on the minimum diameter that would satisfy the maximum pressure drop criteria is given.

This diameter is used in the correlation

$$surface\ equipment\ cost_{per\ foot} = 0.4249 \times {D_f}^2 - 0.0472 \times D_f + 40.863$$

This cost is in 2001 dollars. The PPI for pipe is applied to bring the estimate to current dollars (or the year being evaluated). The updated cost is multiplied by the specified distance between the well and plant to determine the surface equipment cost per well. This cost is applied to all wells supporting plant operations.

This approach is used for both binary and flash plants, recognizing that the approach used to size the piping is based upon the properties of liquid water. With flash plants, it is probable that the geothermal flow in the production surface piping will be two-phase, and the approach described will underestimate the size and cost of the piping required. This is, in part, why GETEM's default for the allowable pressure drop is lower (5 psid) for flash plants.

The surface equipment costs that are estimated do not include any separators or other equipment at individual wellheads. Nor does GETEM attempt to define surface piping systems where fluid from individual wells would flow to or from a main production or injection line going to or from a plant.

A8: GEOTHERMAL PUMPING

Pumps are utilized with geothermal resources to increase flow, and by doing so reduce the number of wells required to support a specified level of power sales, or increase the power sales from a fixed number of wells. There are costs associated with this pumping that diminish, and in some instances negate, the benefits of increasing flow. These costs include the capital and maintenance costs for the pumps, as well as power needed to operate the pumps.

In GETEM, the power needed for operating the geothermal pumps is assumed to be generated by the power plant. The power sales for a project is the difference between the net output from the power plant and this geothermal pumping. Figure A-12 below illustrates the impact of pumping on power sales. It plots the fraction of the plant output required for production well pumping as a function of the required pump setting depth for three different temperatures.

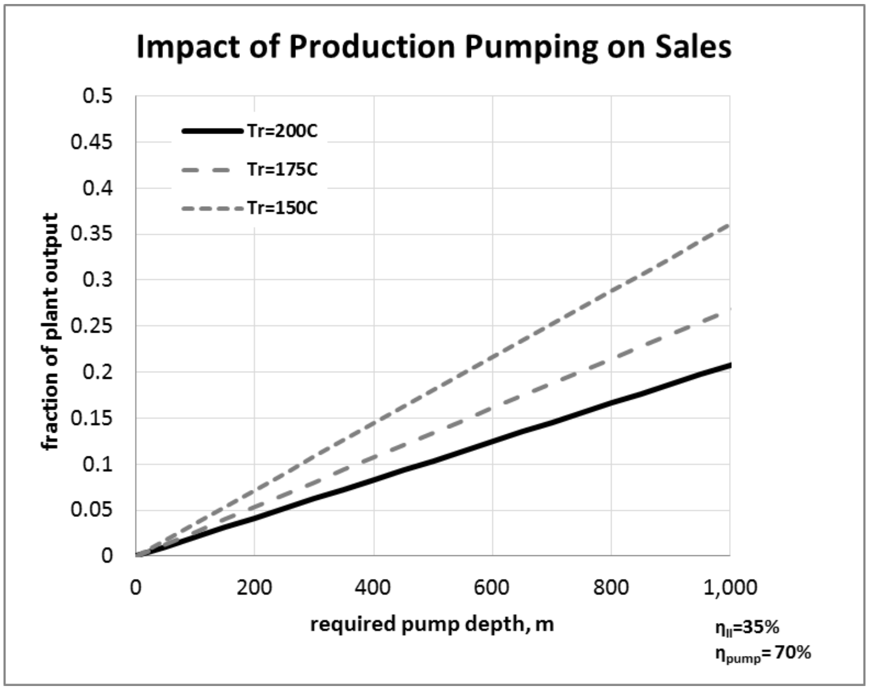


Figure A-12. The impact of production pumping on power sales.

This figure is idealized in that it assumes that the flow rate is constant at all pump depths, that friction losses are negligible, and that the pump suction pressure is equivalent to the fluid pressure at the production wellhead. With these assumptions, the head developed by the pump is equivalent to the setting depth, and the results shown do not change regardless of the magnitude of the flow rate assumed. The sensitivity of power to resource temperature results from lower temperature fluids having less potential to produce work; the specific pumping power (power per unit mass flow) is the same for all temperatures at a given depth.

Geothermal pumping also includes the injection pumping power. With the assumptions made, results for injection pumping are the same when the required injection pump head and the pump production depth are equivalent and the produced and injected flow are the same. For example, a well with a temperature of 150°C and a production pump depth of 400 m, ~15% of the plant output would be required for the production pump. If the required injection pump head were 400 m, then ~15% of the plant output would also be required for the injection pump, or a total of ~30% of the plant output needed for geothermal pumping.

Though this is an idealized representation of pumping power, it is informative in that it illustrates that there is a cost associated with pumping that increases with flow rate per well. Because of this cost, there is an economic optimum where the effect of the added pumping power to increase well flow offsets the reduction in well count associated with that increased flow per well.

In GETEM's determination of pumping power, both the pumping depth required and the injection pump head are determined. These determinations are functions of the input provided and calculations made; they include the effects of friction, any difference in the flow to an injection well and a production well, fluid temperature losses in the well bore, hydrostatic pressure, well depth, and the well casing design.

Approach

The conversion system used establishes whether a production well will default to having a downhole production pump. Binary plants default to having production pumps; flash steam plants default to having artesian flow production wells. One can revise these defaults, and GETEM will calculate an LCOE even though it is probable that with binary plants, warnings will be received that flashing has occurred in the production well. Note that if flashing occurs, GETEM does not revise its estimate of the production wellhead temperature used for binary plants (the assumption remains that geothermal fluid at the wellhead is a single phase liquid).

Figure A-13 below shows key parameters that the model uses in determining the setting depth for the production pump and the injection pump head.

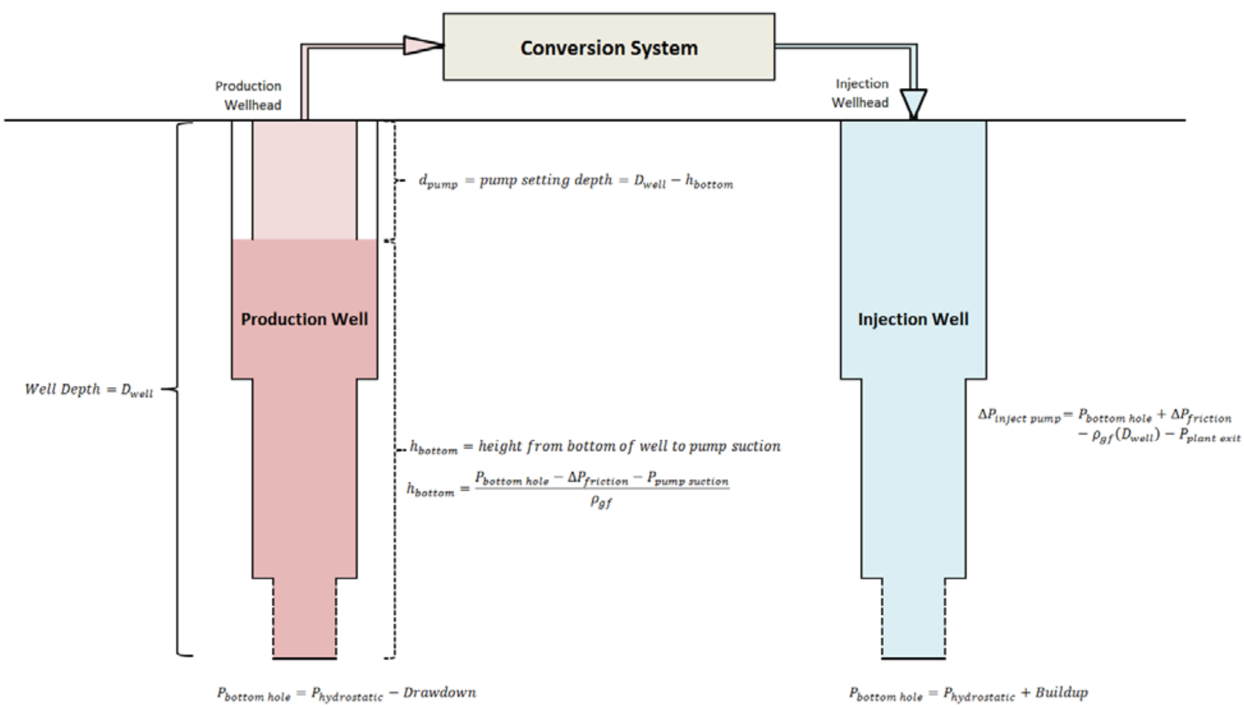


Figure A-13. Key parameters used in determining the setting depth for the production pump and the injection pump head.

The following sections provide specifics as to how GETEM determines these parameters when they are not specified inputs.

Hydrostatic Pressure

GETEM's calculation of pumping power is based on its estimate of the pressure in the reservoir. This reservoir pressure essentially "pushes" fluid up the production well, and "pushes" against any fluid being injected. In determining pumping power, this reservoir pressure is represented by hydrostatic pressure, or the pressure of a column of water having height equivalent to the resource depth, with the water column being in thermal equilibrium with the earth from the surface to the bottom of the production well. Xie, Bloomfield, and Shook (2005) used the following correlation for the hydrostatic pressure:

$$P_r(h) = P_o + \frac{1}{C_p}\left[e^{\rho_o g C_p\left(h - \frac{C_T}{2}\Gamma_T h^2\right)} - 1\right]$$

P_o, ρ_o = fluid pressure and density at surface condition

C_P = pressure gradient

C_T = temperature gradient coefficient

h = reservoir depth

Γ_T = earth temperature gradient.

For a typical hydrothermal reservoir, the authors used C_P = 4.64 × 10-7 KPa^{-1} or 4.64 × 105 bar^{-1} and C_T = 9 × 10-4$°C^{-1}$.

The temperature gradient coefficient was modified for use in GETEM as shown below. This modification was made after comparing the pressure calculated with the above correlation to the density head of water calculated at 5-meter intervals from the surface to depth. At each interval, the fluid temperature increased according to an earth temperature gradient, which was used to determine the density of the fluid using the pressure of the immediate above interval. This density head calculation indicated that for the deepest wells being considered for EGS, the above correlation predicted pressures that were ~4% lower, indicated by the density head calculation. The effect of a lower hydrostatic pressure is to increase the pump setting depth and the production pumping power that is required. With the correction to the temperature gradient coefficient given below, the correlation produces hydrostatic pressures that are ~0.5% lower than the calculated density head for depths to 6 km.

$$C_{T,revised} = \frac{9\times 10^{-4}}{\left[30.796\times T_R{}^{-0.552}\right]}, °C^{-1}$$ where T_R is the resource temperature in °C

GETEM's determination of both production and injection pumping power is dependent upon the bottom hole pressure in the well. For hydrothermal resources, the bottom hole pressures are:

$$P_{production-bottom\ hole} = P_{hydrostatic} - drawdown_{production\ well}$$
$$P_{injeciton-bottom\ hole} = P_{hydrostatic} + buildup_{injection\ well}$$

In these relationships, the buildup at the injection well and the drawdown at the production well are hydraulic resistance terms that are functions of flow rate.

With EGS scenarios, there is a direct connection between the production and injection well in the reservoir created. With this resource, the bottom hole pressure in the production well can be expressed as:

$$P_{production-bottom\ hole} = P_{injection-bottom\ hole} - Buildup_{injection\ well} - Drawdown_{production\ well}$$

The buildup and drawdown terms in this relationship again represent the hydraulic resistance to flow—in this case, in combination they represent this resistance for the reservoir created.

With EGS resources it is assumed that there will be a hydrostatic pressure that will have to be overcome in order to inject fluid.

$$P_{injection-bottom\ hole} = P_{hydrostatic} + buildup_{injection\ well}$$
$$P_{injection-bottom\ hole} = P_{plant\ outlet} + density\ head, or\ \rho * depth - \Delta P_{friction}$$

The larger of these two values for the bottom hole pressure in the injection well is used in determining the bottom hole pressure in the EGS production well.

Production Well

Pump Depth

For a given resource, increasing production flow from a well requires increasing the depth at which the pump is set. That setting depth corresponds to the location in the well where a minimum allowable pressure occurs; this is the minimum suction pressure for the production pump. In GETEM, this minimum pressure is

$$P_{minimum} = P_{saturation} + P_{ncg} + NPSH$$

where

$P_{saturation}$ is the saturation pressure at the fluid temperature

P_{ncg} is the pressure necessary to keep non-condensable gases in solution

$NPSH$ is the net positive suction head for the pump.

GETEM determines a saturation pressure; the other two terms are combined as a single input value to the model (the excess pressure at the pump suction, or P_{excess}).

$$P_{excess} = P_{ncg} + NPSH$$

This term represents the pressure needed above saturation to prevent pump cavitation. It assumed the minimum pressure ($P_{minimum}$) is also the pressure at the production wellhead, with the defined excess pressure keeping the fluid from flashing between the wellhead and the power plant (binary plant heat exchangers). The minimum pressure can also be expressed as:

$$P_{minimum} = P_{bottom\ hole} - \Delta P_{friciton} - \rho_{gf}(h_{bottom}),$$

where

$\Delta P_{friction}$ is the friction loss as the fluid flows up the well

ρ_{gf} is the density of the geothermal fluid

h_{bottom} is the distance from the bottom of the well to the location where the minimum pressure occurs.

The difference between the depth of the well (D_{well}) and the point in the well where the minimum pressure occurs (h_{bottom}) is the pump depth (d_{pump}). This allows the minimum pressure to be expressed as:

$$P_{minimum} = P_{bottom\ hole} - \Delta P_{friciton} - \rho_{gf}(D_{well} - d_{pump})$$

The two expressions for the minimum pressure can be combined, producing the following solution for the pump depth, d_{pump}.

$$d_{pump} = D_{well} - \left[\frac{p_{bottom\ hole} - \Delta P_{friction} - P_{saturation} - P_{excess}}{\rho_{gf}}\right]$$

As indicated, the bottom hole pressure in the production well is the hydrostatic pressure less the drawdown. In GETEM, this bottom hole pressure is determined as:

$$P_{production-bottom\ hole} = P_{hydrostatic} - drawdown, \text{ where}$$

$$drawdown = \frac{flow\ rate_{well}}{productivity\ index}$$

Both the flow rate per well and the productivity index are specified inputs.

GETEM determines the pump setting depth by first solving for the pressure at the bottom of the upper casing interval, with the premise that the production pump will be set in this casing interval, which will have a 13 5/8-inch diameter casing (or larger) in order to accommodate the production pump. This pressure is determined by calculating the pressure change in each interval below the upper casing in the well.

$$P_{bottom\ upper\ casing\ interval} = P_{bottom\ hole} - \sum_{1}^{\#intervals-1} \left[\Delta P_{depth} + \Delta P_{friction}\right]$$

In this relationship, ΔP_{depth} is the change in the density head across an interval.

$$\Delta P_{depth} = \rho_{gf} * height_{interval}$$

In calculating the pressure drop due to this change in the density head, GETEM uses a density that is based upon the average temperature of the geothermal fluid interval, considering a temperature loss of the fluid to the surrounding earth.

The friction losses are determined for each interval using:

$$\Delta P_{friction} = f * \left(\frac{L}{D}\right) * \frac{V^2}{(2 * g)} * \rho$$

where

ρ = fluid density based on the average temperature

f = friction factor (determined using Serghide's solution, assuming turbulent flow)

L = length of interval

D = diameter of interval

V = fluid velocity in interval

g = gravitational constant.

The Serhide solution for the Darcy friction factor indicates a surface roughness for the casing or well bore. For casing and liners, a surface roughness of 0.00015 ft is used. This value is from the Crane Technical Paper No. 410 (1942) for steel pipe. The value used for an open hole interval is 0.02 ft; this is twice the value in the Crane 410 for rough concrete pipe. The value used for a slotted liner is 0.001 ft. This is the approximate value determined using a correlation from Clemo (2006) and a hole porosity of ~10% (the values considered in Clemo's paper ranged from <1% to ~12% for slotted casing/liners). These values are not specified inputs; they are fixed values in GETEM. They are shown on the *GF Pumping* worksheet, rows 49–51.

After determining the pressure at the bottom of the upper casing interval where the pump is set, the pump depth is determined using:

$$d_{pump} = D_{upper\ casing\ interval} - \left[\frac{p_{bottom\ of\ upper\ interval} - \Delta P_{friction} - P_{saturation} - P_{excess}}{\rho_{gf}}\right]$$

In this relationship, $D_{upper\ casing\ interval}$ is the depth of the upper interval. If this relationship produces a pump depth that is <0, no pump is required.

Pumping Power

The geothermal production pumping power per well is based on the required pump depth that is determined and the specified well flow rate. As indicted earlier, the model assumes that the pump delivers the fluid to the surface (well-head) at a pressure equivalent to the pump's suction pressure. With this assumption the pump head is:

$$head_{pump} = d_{pump} + \Delta P_{friciton-pump\ casing}, \text{ or}$$

$$head_{pump} = d_{pump} \times \left[1 + f * \left(\frac{1}{D}\right) * \frac{V^2}{2 * g}\right]$$

The determination of the friction loss in the pump casing uses the same approach as used in determining the loss in the different intervals in the well. In this calculation, the diameter of the pump casing is specified, while GETEM uses default diameters for each of the intervals in the well.

Once the pump head is determined, the well pumping power is found using:

$$power_{well} = \frac{[flow_{well} \times head_{pump}]}{\eta_{pump\ \&\ driver}}$$

The term $\eta_{pump\ \&\ driver}$ is the combined efficiency of the pump and driver. This is a specified input value. GETEM defaults to using a value of 75% for the pump and 90% for the driver (a combined efficiency of 67.5%). This value is the power required per well. The production pumping power required for the project is the product of the power determined for each well and the number of production wells used to supply fluid to the plant.

Pump Cost

The cost of the production pump and driver are based on a correlation that relates cost to the horsepower required.

$$pump\ cost_{production} = \$1{,}750 \times (pump\ hp)^{0.7} + \$5{,}750 \times (pump\ hp)^{0.2}$$

In this relationship, *pump hp* is the pumping power calculated for a single production well. The first term in this relationship is for the equipment (pump and motor); the second term is for the surface installation (electrical and control). This cost relationship is based on pump and driver (electric motor) cost estimates from Aspen's Icarus Process Evaluator that were in 2001 dollars. This cost is adjusted to the year for which the evaluation is being performed using a PPI for pumps.

GETEM also includes an estimate for installing the pump in the well. That cost includes a workover rig, an installation cost per ft of depth, and a casing cost (also per foot of depth). These values are specified inputs to the model.

When estimating the maintenance cost for the production pump, it assumes that the pump and driver are replaced at a specified periodic interval. That replacement cost is the equipment portion of the pump cost.

$$pump\ \mathrm{replacement}\ cost_{production} = \$1{,}750 \times (pump\ hp)^{0.7} \times PPI_{pump}$$

In addition, the estimated installation cost is included, less the cost for the pump casing.

Flash Steam Scenarios

When flash steam plants are used, GETEM defaults to not using production pumps and allowing the geothermal fluid to flash in the production well bore. With this scenario, GETEM attempts to estimate the pressure of the two-phase flow when it reaches the surface. If the value is less than the optimal flash pressure determined, a warning will appear. If the value is less than 1 atm, another warning will appear.

The determination of where flashing occurs is similar to that used to determine the setting depth of a production pump. As shown below, the main difference is that the excess pressure term to prevent cavitation is not included.

$$d_{flash} = D_{upper\ casing\ interval} - \left[\frac{p_{bottom\ of\ upper\ interval} - \Delta P_{friction} - P_{saturation}}{\rho_{gf}}\right]$$

When flashing occurs, the wellhead pressure determined is only a rudimentary estimate. It is based on an estimate of the change in the fluid density as the two-phase mixture continues to flash as it rises in the well. As the fluid flashes, its density decreases, which reduces the pressure change, due to the change in weight of the column of fluid above as the fluid rises in the well. The effect of this density change is estimated as:

$$\frac{\rho_{sat}}{\rho_{effective}} = a \times {d_{flash}}^{b} + 1 \text{ , where}$$

d_{flash} is depth to flashing in feet

$a = 33.263e^{-0.035468T_{gf}}$

$b = 0.42512e^{0.002486T_{gf}}$, where

T_{gf} is the temperature where the fluid begins to flash in °C.

This estimate of $\rho_{effective}$ is based on the estimates of the effect of a two-phase mixture on pressure at the surface when the fluid begins to flash at some point in the well. These estimates were done for depths to 1 km and temperatures from 150°C to 300°C. In doing these estimates, the effect of a one-meter increase in elevation on pressure was estimated from the point where flashing started to the surface. The total change in pressure was used with the depth to flashing to establish an effective density for that assumed set of conditions.

The $\rho_{effective}$ represents the effective density producing the change in pressure from a column of water having a height equivalent to the depth at which flashing occurs. If there were no frictional losses, the wellhead pressure would be:

$$P_{well-head\ (no\ friction)} = P_{saturation} - \rho_{effective} \times d_{flash}$$

As the density changes, so does the velocity of the fluid. To estimate the frictional losses, an effective velocity was determined as:

$$V_{effective} = V_{prior\ to\ flashing} \times \frac{\rho_{sat}}{\rho_{effective}}$$

This velocity is used to estimate the friction loss once flashing started.

$$\frac{head\ loss_{flashing}}{unit\ length} = \frac{head\ loss_{prior\ to\ flashing}}{unit\ length} \times \left(\frac{V_{effective}}{V_{prior\ to\ flashing}}\right)^2$$

The wellhead pressure, including friction, is estimated as

$$P_{well-head\ (no\ friction)} = P_{saturation} - \rho_{effective}\left[d_{flash}\left(1 + \frac{head\ loss_{flashing}}{unit\ length}\right)\right]$$

Again, this is a simple estimate of the wellhead pressure when flashing occurs. It is meant to provide an indication that the specified flow rates may be too high, and that either the flow rate should be reduced or the specified flash pressure lowered.

Injection Well

Injection Pump Head

GETEM estimates the pressure that is needed at the bottom of the injection well to overcome the combined hydrostatic pressure of the reservoir and the hydraulic resistance associated with flow into the reservoir (*buildup*).

$$P_{injection-bottom\ hole} = P_{hydrostatic} + buildup \text{ , where}$$

$$buildup = \frac{flow\ rate_{well}}{injectivity\ index}$$

The injectivity index is a specified input; another input specifies the relative flow between successful production and injection wells. This bottom hole pressure represents the minimum pressure needed to inject the well flow. If the bottom hole pressure determined from the fluid density head and well-head pressure is less than this value, an injection pump is required to overcome the difference.

The pressure, due to the density head of the fluid in the well, is determined using a similar approach to that used when determining the setting depth for the production pump. In the injection well, the calculation proceeds from the plant outlet to the bottom of the well, assuming no injection pump is used.

$$P_{rho\ head-injection\ well} = P_{plant\ outlet} + \sum_{1}^{\#intervals} \left[\Delta P_{depth} - \Delta P_{friction}\right]$$

The ΔP_{depth} is the increasing pressure in the well due to the weight of the above column of water.

$$\Delta P_{depth} = \rho_{gf} * height_{interval}$$

In making this calculation for each interval in the injection well, it is assumed that the surrounding earth heats the water flowing down the well. The same temperature gradient corresponding to the temperature loss in the production well is applied to the fluid in the injection well. Note that this approach does not necessarily depict the flow in deep wells with low flow rates where, for a portion of the injection well depth, the injected fluid may be warming the surrounding earth. For most scenarios where the flow rates are representative of operating facilities, the temperature change in the injection well is small, which is reflected in the model's estimates.

In the injection well, friction losses reduce the effect of the density head.

$$\Delta P_{friction} = f * \left(\frac{L}{D}\right) * \frac{V^2}{(2 * g)} * \rho$$

where

ρ = fluid density based on the average temperature for the interval

f = friction factor (determined using Serghide's solution, assuming turbulent flow)

L = length of interval

D = diameter of interval

V = fluid velocity in interval

g = gravitational constant.

The plant outlet pressure used in the previous relationship for the head pressure in the injection well is based on a specified pressure drop through the surface equipment for binary plants, or the lowest flash pressure for flash steam plants. In GETEM, the pressure leaving the plant is assumed to be equivalent to the injection well-head pressure, exclusive of any injection pumping.

$$P_{plant\ outlet} = P_{production\ well\ head} - \Delta P_{surface} \text{ , if binary}$$
$$P_{plant\ outlet} = P_{lp\ flash} \text{ , if flash}$$

If the required bottom hole pressure is less than the head pressure in the injection well, no injection pumping is needed. If it is greater, then a pump is required. The pressure that is required is:

$$\Delta P_{inject-pump} = \left[P_{injection-bottom\ hole} + P_{excess}\right] - P_{rho\ head-injection\ well}$$

The required bottom hole pressure ($P_{injection\text{-}bottom\ hole}$) is the minimum pressure that must be overcome to inject fluid. GETEM includes an input to adjust this minimum (P_{excess}); the default is 1 psi. Combining all the terms, the necessary additional pressure from an injection pump is:

$$\Delta P_{inject-pump} = [P_{hydrostatic} + buildup + P_{excess}] - \left(P_{plant\ outlet} + \sum_{1}^{\#intervals} [\Delta P_{depth} - \Delta P_{friction}] \right)$$

If this value is >0, a pump will be used.

Injection Fluid Temperature

The determination of the additional pumping pressure required to inject the geothermal fluid is dependent upon the temperature of the fluid being injected. A colder fluid has a higher density that increases the head pressure in the well and decreases the additional pressure provided by the injection pump.

With flash plants, the temperature of the geothermal fluid being injected corresponds to the fluid at the lowest flash pressure in the plant. With binary plants, the temperature of the fluid injected is a function of plant performance. More efficient plants (second law efficiency) extract more energy from the geothermal fluid and have lower outlet temperatures. The outlet temperature in binary plants is estimated as a function of performance (second law efficiency η_{II}).

$$T_{exit-K} = T_{in-K} \times [1 + b(\eta_{II})]$$

In this relationship, both temperatures are in °K. The b term is a function of the inlet temperature.

$$b = -0.002954 \times T_{in-C} - 0.121503$$

In calculating this term, the inlet temperature (T_{in}) is in °C.

This relationship between the outlet temperature and the plant second law efficiency is based upon the modeled results used to establish the correlations between binary plant performance and cost. It does not represent an actual modeled state point condition; rather, it is indicative of how the plant performance affects the temperature of the fluid leaving the plant. Figure A-14 below shows the modeled plant outlet temperatures that were the basis for the cost correlations developed and used in GETEM (left; the temperature ratio is in absolute temperature units). The right side of Figure A-14 shows the fit of the correlation developed to the modeled outlet temperatures with a 175°C resource.

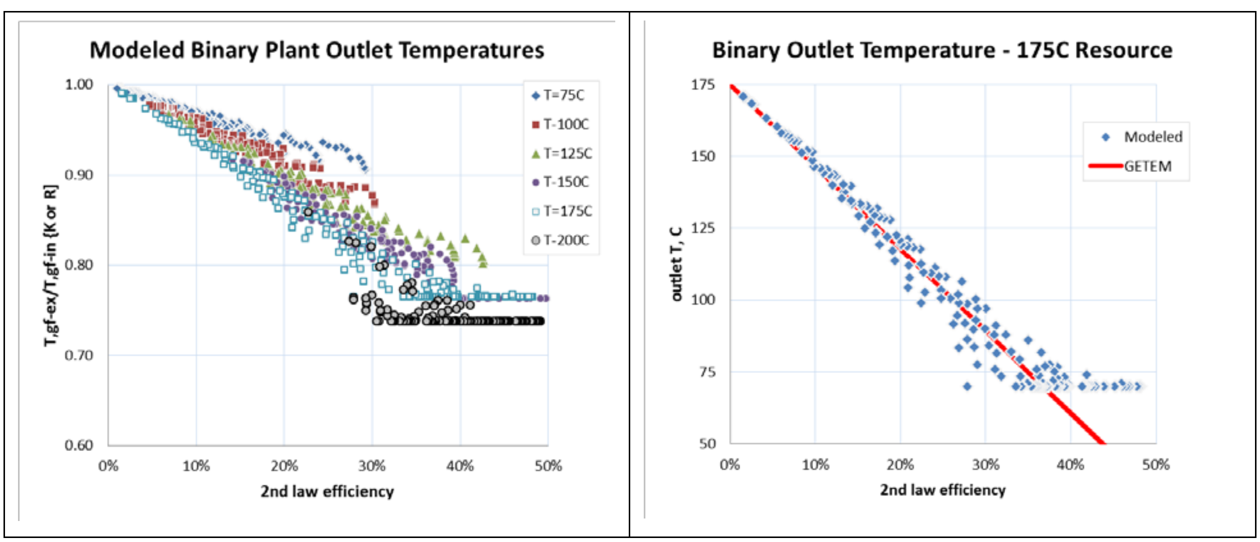


Figure A-14. Effect of binary plant conversion efficiency on calculated geothermal outlet temperatures for both multiple resource temperatures (left) and a 175°C resource (right).

The right side of Figure A-14 illustrates the effect of a geothermal temperature constraint on the modeled results. This constraint is imposed to prevent precipitation of amorphous silica; for the 175°C resource, the constraint is ~70°C. The correlation used to estimate the outlet temperature is also shown in the right of the figure. When the estimated temperature is less than the constraint, the silica temperature constraint is used as the temperature leaving the plant. At this resource temperature, this would occur once the conversion efficiency exceeds ~37%.

Though difficult to see in the left side of Figure A-14, the model results for the resources 125°C and lower did not reach the minimum temperature constraint. Though this constraint does limit the potential performance, it is inherent to GETEM's calculations for binary plants. Calculations of binary cost and performance do not include the use of recuperation, which could offset a portion of the performance penalty associated with this constraint.

The temperature constraint for silica precipitation is determined using correlations for the solubility of quartz and silica as functions of temperature taken from Gunnarsson and Arnorsson (2000). Early versions of GETEM used correlations based on the solubility of both chalcedony and quartz. Their use produced a discontinuity in the outlet temperatures and generation costs when going from one to the other (at ~180°C). The use of the solubility correlations in Gunnarsson's paper resolved those issues.

The only use of this temperature is in determining water properties in the injection well. While cooler fluids increase the density head in the injection well and reduce the pumping required, they also have a higher viscosity that would increase the pressure buildup at the bottom of the injection well. This is not calculated; to do so is beyond the capabilities of GETEM. If it is a concern, then the injectivity index should be adjusted accordingly.

1.3.1.1 Pumping Power

The determination of the injection pumping power deviates from the approach used for the production well, in which it is assumed that each well has a production pump (when binary plants are used). The premise for injection pumping is that one or more injection pumps will be located at a central location (likely the power plant). Fluid is pumped from this location to all wells used for injection. The power required is determined using additional pressure needed in a successful injection well and the total flow injected.

$$power_{injection} = \frac{\left[total\ flow_{injection} \times \frac{\Delta P_{inject-pump}}{\rho_{gf-plant\ outlet}}\right]}{\eta_{pump\ \&\ driver}}$$

In determining the injection pumping power, the value used for the pump and driver efficiency is the same as that specified for the production pump.

The total injection flow may not be equivalent to the total production flow. With EGS resources, the injected flow includes both all produced flow and any makeup for subsurface losses. Subsurface losses are specified as a fraction of the injected flow. Appendix A9 has further discussion on how the magnitude of this makeup flow is determined.

$$total\ flow_{injection} = total\ flow_{production} + water\ loss_{subsurface}$$

For hydrothermal resources using flash plants, the steam condensate is the assumed source of makeup water for the plant's evaporative cooling system. In GETEM, if these losses to the geothermal flow are made up with hydrothermal resources, the injected flow is equal to the produced flow. If these losses are not made up (which is the GETEM default), water losses for the heat rejection are estimated and subtracted from the total production flow to determine the amount of water injected. The approach used to determine the water lost in heat rejection is discussed in Appendix A11.

If these losses are not made up, the total injection flow is:

$$total\ flow_{injection} = total\ flow_{production} - water\ loss_{heat\ reject}$$

With EGS resources using flash plants, all water losses in the plant are made up. The injected flow includes all produced flow and subsurface losses (the same as for EGS binary plants).

Pump Cost

In determining the cost for injection pumping, a maximum size limit of 2,000 hp is placed on a pump. The number of pumps used is determined by dividing the total pumping power by this limit. The number of pumps determined is rounded up to the next integer value. As an example for a total injection pumping power of 2,500 hp, the injection pump cost would be based on the use of two 1,250 hp pumps.

The cost used for each injection pump includes both the equipment cost and an installation cost. There is one correlation for the equipment costs for pumps and drivers; the same correlation is used for production pumps.

$$equipment\ cost_{injection\ pump} = \$1{,}750 \times (pump\ hp)^{0.7}$$

The installed cost of an injection pump is determined by applying an installation multiplier to the equipment cost.

$$installed\ cost_{injection\ pump} = equipment\ cost_{injection\ pump} \times installation\ multiplier$$
$$installation\ multiplier = 3 \times (pump\ hp)^{-0.11}$$

This cost is in 2001 dollars; it is adjusted to the estimate year using the PPI for pumps. Again, this is the cost for a single pump. The total cost for the injection pumps is this pump cost multiplied by the number of pumps used.

Supplemental Injection

GETEM allows for the use of failed wells to supplement injection. GETEM's determination of injection pumping power is based on the additional pressure needed for a successful well. This pump pressure is used to estimate the flow that the failed well with the lower injectivity will accept. The use of these wells does not impact either the estimates of the injection pumping power or the injection pumping cost. Their use impacts the number of successful injection wells that are needed, and the total number of wells drilled (see Appendix A5).

Reservoir Performance

Reservoir performance, specifically its hydraulic performance, can significantly impact the amount of power required for pumping the geothermal fluid. The metrics used to characterize the effect of the reservoir performance on pumping are the flow per well and the productivity/injectivity indices; these are inputted values. There is further discussion on these inputs in Appendix A9.

The pumping power determined is based on these specified inputs at the start of operations. Though it is probable that the reservoir performance will evolve over time, the premise for GETEM is that it does not. The flow rate and the productivity/injectivity remain constant, and it is assumed that the decline in resource productivity (temperature) does not impact the geothermal pumping. With these assumptions, the geothermal pumping power is not expected to change over the project life. This assumption is inherent to the calculation of the effect of the decline in resource temperature on power sales over the life of the project.

Well Configuration

An assumed configuration for both the production and injection wells is used in estimating both the friction losses and temperature drop in a flowing well. The configuration is based upon the depth of the well, the production/injection interval size (smaller or larger diameter), and whether the production/injection interval is open or has a perforated/slotted liner.

The well configuration is based on the number of intervals (casing or liners) required in drilling the well. The possible configurations considered are shown below in Figure A-15. The designation of the number of intervals is based on the bottom injection/production interval plus the number of casing/liners installed above the bottom interval. (The conductor casing is not included in the interval count.)

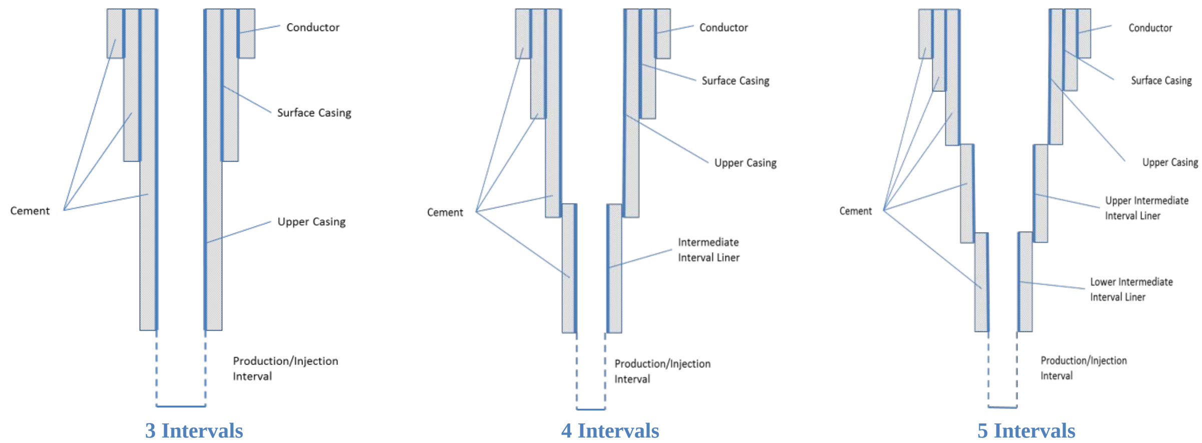


Figure A-15. Well configurations, with three, four, and five intervals, respectively.

The configuration on the left has three intervals—the surface casing, the upper casing and the production/injection interval. The configuration on the right has five intervals—the surface casing, the upper casing, the upper intermediate interval liner, the lower intermediate interval liner, and the production/injection interval. The differentiation in GETEM between a casing and a liner is that casing comes from depth back to the surface, while liners are "hung" within the well. (They are not run back to the surface.) All casing is cemented in place, as are all liners, except for that in the production/injection interval. When estimating friction losses, only intervals through which fluid flows are considered; hence, in the determination of the pumping power, the number of intervals is always the value shown in Figure A-15 less one.

The production pump is installed in the upper casing interval; to accommodate the pump, the minimum diameter in this interval is 13 $^{5}/_{8}$ inch when a pump is used.

The model defaults to a bottom hole configuration using the following logic:

- For both EGS and hydrothermal resources with binary plants, the model defaults to the larger-diameter well.
- For both EGS and hydrothermal resources with flash plants, the model defaults to the smaller-diameter well.
- Injection wells have the same diameter as production wells.
- EGS wells have perforated or slotted liners in the production/injection intervals; hydrothermal wells are open-hole in the bottom intervals.

Though EGS well flow rates are postulated to be less than flows from hydrothermal wells in the near term, the larger-diameter wells are used with production pumps in order to accommodate a production pump. Table A-5 below shows the defaults used by the model to define the well configuration.

Table A-5. Defaults used by GETEM to define well configuration.

Depth	<3 km	3-5 km	≥5km
# casing intervals	3	4	5
# intervals with flow	2	3	4
Bottom hole diameter larger well			
Open	12.25-inch	12.25-inch	12.25-inch
Slotted liner	9.625-inch	9.625-inch	9.625-inch
Upper casing diameter larger well	13.625-inch	18.625-inch	24-inch
Bottom hole diameter smaller well			
Open	8.5-inch	8.5-inch	8.5-inch
Slotted liner	7-inch	7-inch	7-inch
Upper casing diameter smaller well	9.625-inch	13.5-inch	20-inch
Length: Surface casing	800 ft	1,200 ft	1,200 ft
Length: Upper casing	80% of depth	40% of depth	30% of depth
Length: Upper liner	NA	40% of depth	30% of depth
Length: Intermediate liner	NA	NA	30% of depth
Length: Production/injection interval	20% of depth	20% of depth	10% of depth

Again, the production pump is set in the upper casing; the maximum setting depth for an electric submersible pump is established by the casing length for this interval. The maximum depth for a line-shaft pump is assumed to be 2,000 ft, or 610 m. (If this depth is exceeded, a warning should occur.)

Temperature Loss in Well Bore

GETEM includes a simplified estimate of the temperature loss in the well bore as fluid flows up the well. While the loss might be considered negligible in productive, shallow hydrothermal wells, it has the potential to be significant for the deep wells, especially if the wells are less productive (lower flow rates).

The method used is adapted from Ramey's article in the *Journal of Petroleum Technology* (Ramey 1962); equations (1), (2), (3), and (5) in this paper are used. This methodology provides an estimated solution for the temperature loss, assuming the heat transfer from the well bore to the earth is unsteady transient conduction. The calculation assumes that the sufficient time has occurred since beginning flow that the simple solution provided by Ramey can be applied. The paper suggests 1 week; GETEM uses 1 year. Each interval in the well is divided into three segments of equal length and the fluid temperature estimated at each point.

The temperature loss in the well is used in estimating the pumping power required. The production wellhead temperature determined is also used in estimating the power plant performance and cost.

An example of the estimated temperature loss in the production well is given in Figure A-16 below for two different resource temperatures, each at two different resource depths. This is indicative of how flow and depth impact the production temperature in GETEM.

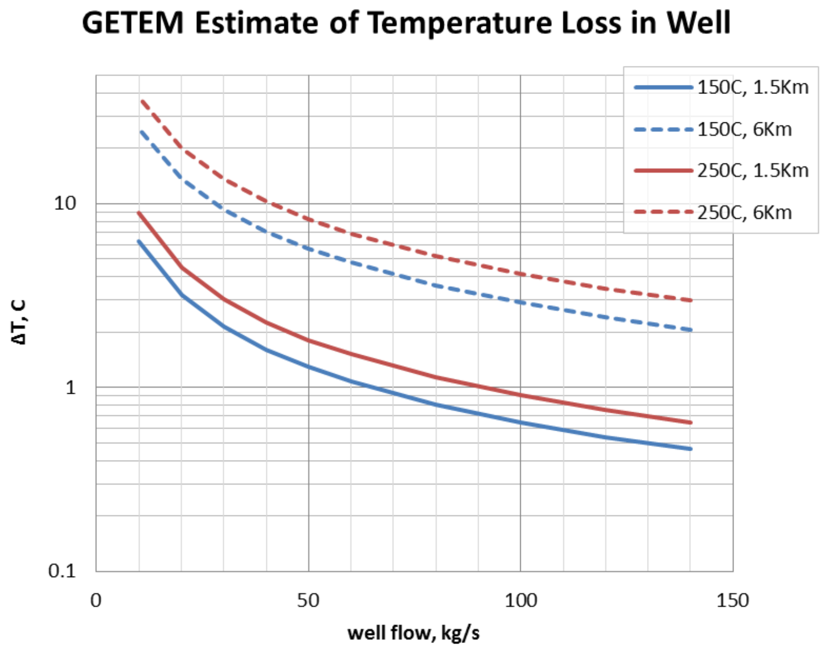


Figure A-16. Estimated temperature loss in the production well.

The consequence of this temperature loss is a reduced potential to produce power. Below in Figure A-17 is the effect of a temperature loss on the ideal power at these two resource temperatures. This loss in available energy is indicative of the actual reduction in generation/sales that would occur. To offset the loss, more flow and wells would be needed.

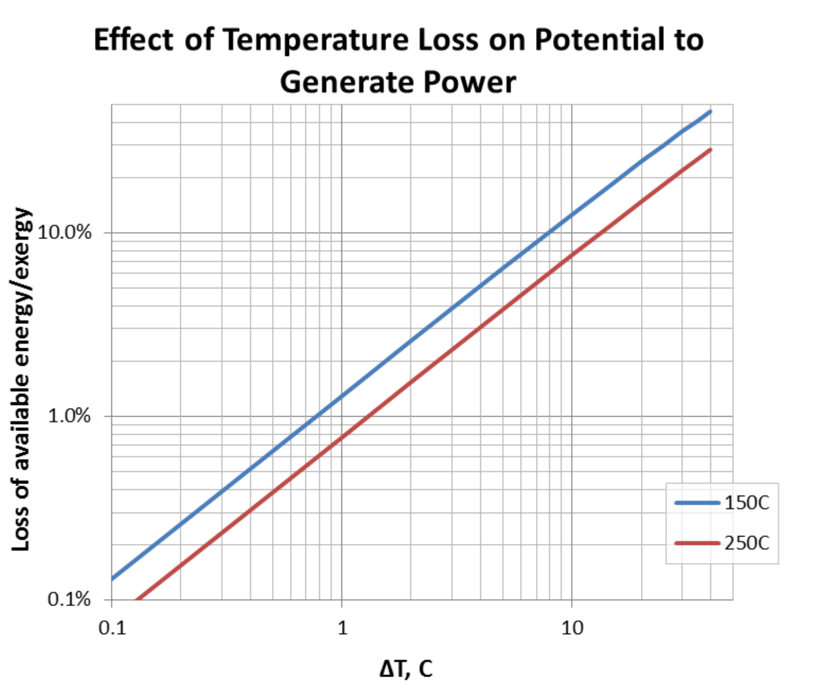


Figure A-17. The effect of a well bore temperature loss on the idea power at 150 and 250°C.

A9: RESERVOIR

Production Well Flow

The production well flow can have a significant influence on the LCOE determined. As shown in Figure A-18 below, this flow affects the sizes of both the plant and the well field.

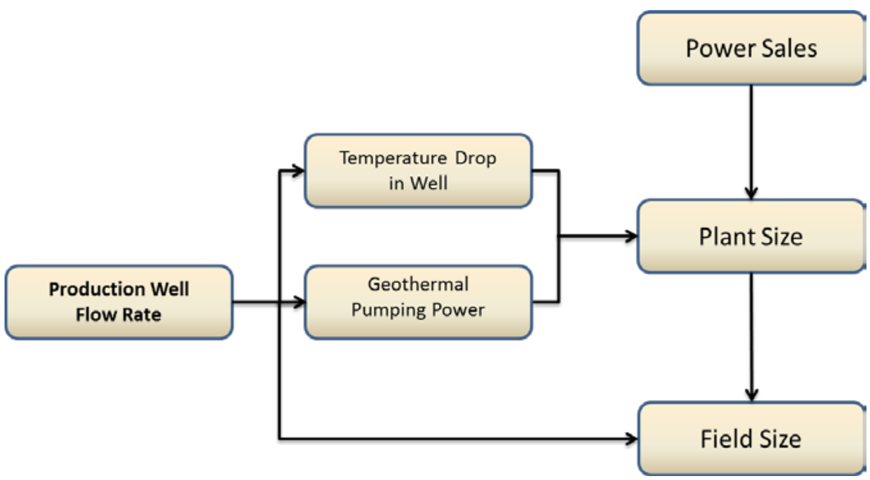


Figure A-18. Production well flow rate as it affects plant size and well field size.

Though it may not be readily apparent, for a given scenario there is likely to be an optimal well flow rate. If the flow rate is too high, the effect of the increased pumping power negates the benefit of the higher flow rate per well. This is illustrated in Figure A-19 below, which shows the impact of flow on the size of the plant, the well count, and the LCOE determined for a DOE GTO–defined scenario (Hydrothermal C). In this figure, all other default values remain constant with only the flow rate being varied. At a flow rate of ~120 kg/s, the LCOE goes through a minimum.

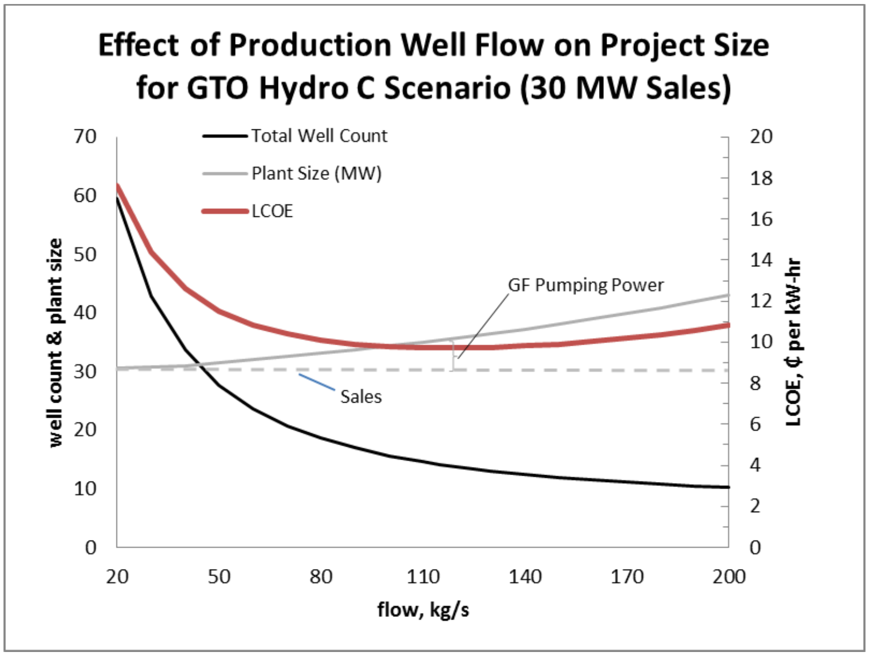


Figure A-19. Impact of flow on plant size, well count, and LCOE determined for GTO Hydrothermal C scenario (see Table 1).

With different resource temperatures and depths, or if other specified inputs are revised, there will still be an optimal flow, though the magnitude will differ.

It is assumed that all successful production wells will operate with the specified value for the production flow rate. In an actual facility, the flow rates would vary between wells, and the value that should be specified is the average flow for the field.

Hydraulic Performance

The hydraulic performance of the reservoir impacts both production and injection pumping power; this impact is represented in GETEM as the pressure drawdown at the production well and pressure buildup at the injection well. These terms impact the calculation of pumping power, which in turn impacts the size of the plant and the number of wells needed to provide a specified level of power sales. Both the pressure drawdown and pressure buildup will change during the initial operation of the well as fluid is withdrawn or returned to the reservoir. The rate at which the pressure changes will lessen with time, and at some point the pressures will reach pseudo-steady state values for a given flow rate. The pressure change when reaching this pseudo steady state condition are the basis for the Productivity and Injectivity Indices, which are the ratio of the flow rate to the pressure change.

$$productivity\ index = \frac{flow\ rate_{prod\ well}}{\left(P_{hydrostatic} - P_{prod\ interval\ at\ time\ t}\right)}$$

$$injectivity\ index = \frac{Flow\ rate_{inject\ well}}{\left(P_{inject\ interval\ at\ time\ t} - P_{hydrostatic}\right)}$$

As suggested by the above relationship, the pressure drawdown or buildup scales linearly with flow rate. This is the premise for the calculation of the geothermal pumping power.

These indices are not calculated; they are specified inputs to the model. The values for these indices will vary between resources, as well as among wells at a given resource. GETEM cannot account for this variability; the values specified are to be representative of the scenario being defined and evaluated.

The default is to use equivalent productivity and injectivity indices for a given resource. The default value used in the model for hydrothermal resources is taken from the ERPI study (EPRI 1996; 2,500 lb/hr-psi). It is probable that in commercial plants, the magnitude of the PP's and II's vary inversely with the resource temperature; for power production from lower temperature resources to be economically viable, the resources must be more productive.

The impact of the productivity and injectivity index used is shown in Figure A-20. Again, this figure is based on the same DOE GTO scenario used in Figure A-19, "Hydro C." The variation in the LCOE determined as a function of flow rate for three scenarios for the productivity and injectivity index is shown (including the default value, 50% of default, and 150% of default). For all three PI/II values considered, the LCOE goes through a minimum. That minimum value is identified with the vertical arrows.

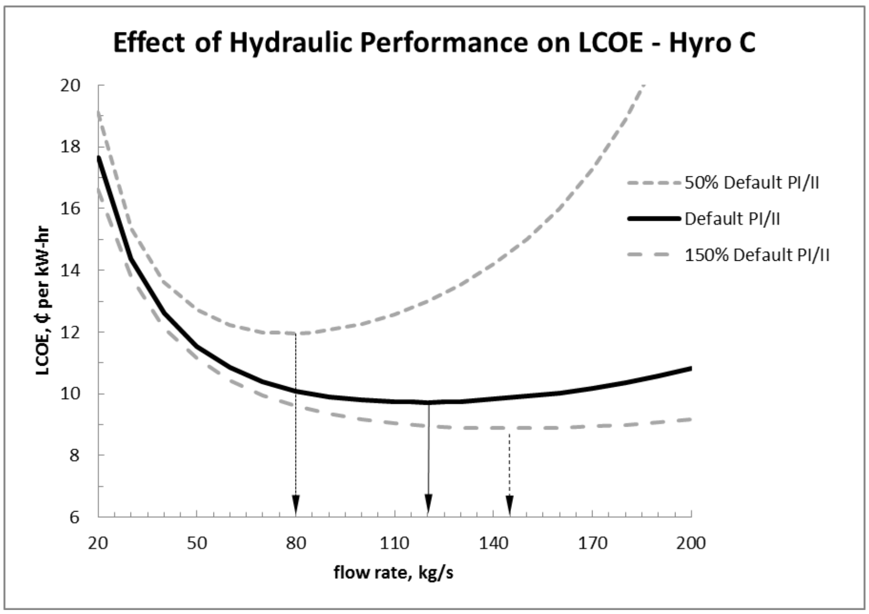


Figure A-20. Effect of hydraulic performance and flow rate on LCOE for the "Hydrothermal C".

Because there is minimal information that can be used to establish representative values for these inputs for EGS resources, it has been assumed that the EGS reservoir created with have both thermal and hydraulic performance equivalent to that of a hydrothermal resource, but at the lower specified EGS well flow rates.

Resource Productivity

GETEM does not model the performance of the reservoir. Rather, it models the impact of reservoir performance on the power sales and the required LCOE. Based on the historical operation of existing geothermal facilities, there is an expectation that, over time, the productivity of the reservoir will decline. This decline in productivity will manifest as a decreasing temperature, pressure, and/or flow rate. GETEM characterizes the decrease in productivity using a declining resource temperature.

Temperature was selected as the metric for assessing the effect of declining productivity because

- nearly all plants experience temperature decline over time

- plant performance is typically more sensitive to changes in temperature than changes in flow
- the effect of temperature on generation can be estimated in a straightforward manner
- in some instances, flow rates increase as operators attempt to offset temperature decline.

With the selection of temperature as the metric for depicting declining productivity, it is inherent to the calculations that the geothermal flow rate remains constant over the life of the project.

Temperature Decline

The decline in the resource temperature with time is specified as an annual decline

$$T_n = T_{initial}(1 - \vartheta_{gf})^n, \text{ where}$$

T is the temperature of the geothermal fluid

n is the point in time (in years)

ϑ_{gf} is the annual decline rate.

The effect of the decline rate on the produced temperature over time is shown in Figure A-21 below.

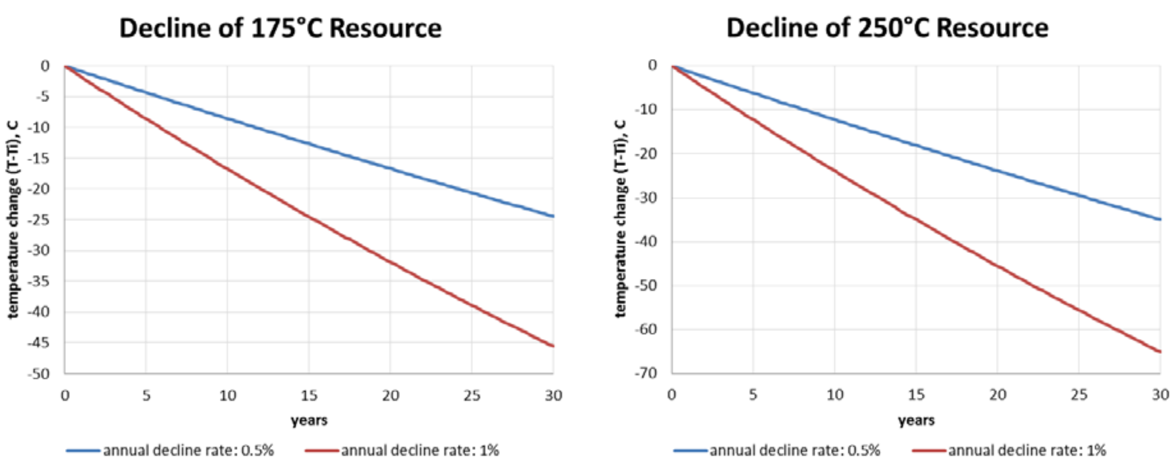


Figure A-21. The effect of the decline rate on the produced temperature over time.

The default values used for the decline rate are based on an evaluation of historical operating data reported to the Nevada Division of Minerals by the geothermal operators (Hanson 2014). The decline rates for the Nevada binary plants typically approach the 0.5% shown in Figure A-21. Similar decline rates were found for flash plants, though there are a limited number of these plants in Nevada. Some plants experienced rates approaching or exceeding the 1% shown. This was often for an abbreviated period, with the rate of decline being mitigated by changing the injection strategy.

Available Energy

Available energy, or exergy, is a measure of the work that can be done in bringing a fluid into equilibrium with a “dead-state” condition (taken to be the ambient) using ideal, reversible processes. This represents that maximum work that could be done by an ideal conversion system. The available energy is defined as

$$\dot{ae} = (h - h_o) - T_o(s - s_o) \text{ , where}$$

$\dot{ae}$ is the specific available energy of the geothermal fluid (per unit mass)

h is the enthalpy of the geothermal fluid

h_o is the enthalpy of the geothermal fluid at the ambient conditions

T_o is the ambient temperature

s is the entropy of the geothermal fluid

s_o is the entropy of the geothermal fluid at the ambient conditions.

The dead-state condition is taken to be the ambient condition corresponding to a mean or average annual temperature. In GETEM, the ambient temperature for binary plants is 10°C; this value cannot be revised, as it is integral to GETEM's determination of the air-cooled binary plant cost. (In the U.S., the average ambient temperature is ~11° to 12°C.) For flash steam plants, a design wet-bulb temperature is specified, which is used as the ambient condition when determining the available energy. Once ambient conditions are fixed, available energy is effectively a property of the geothermal fluid.

Second Law Efficiency

The brine effectiveness and the second law efficiency are used as plant performance metrics. The brine effectiveness is also referred to as the specific power output and the brine utilization factor. It is the net plant output per unit mass flow:

$$brine\ effectiveness = \frac{(generator\ output - plant\ parasitic\ load)}{m_{gf}}$$

In this definition, net plant output is exclusive of the geothermal pumping. This is a fundamental definition used throughout GETEM's calculations. It is the basis for establishing both the plant cost and the size of the well field required.

Unlike the thermal efficiency, which is a measure of how efficiently the extracted heat is converted to power, the second law efficiency is a measure of how efficiently a plant uses a given mass flow of geothermal fluid to produce electrical power. The cost of the power plant varies directly with this efficiency, while the amount of geothermal fluid required to produce a given level of power sales varies indirectly. The second law efficiency is the ratio of brine effectiveness to the available energy:

$$2^{nd} law\ efficiency, \eta_{II} = \frac{brine\ effectiveness}{ae}$$

At a constant geothermal flow rate, a power plant typically achieves its maximum second law efficiency when operating at its design conditions (geothermal and air temperatures). Though this efficiency may initially increase slightly with increasing resource temperature, at some elevated temperature this conversion efficiency will decrease. The plant output will continue to increase with increasing temperature because the available energy is also increasing; however, the increase in plant output will lag behind the increase in available energy because of the second law efficiency decline. If the resource temperature decreases, both the second law efficiency and available energy decrease; the impact on power will be greater than would be expected by considering the change in available energy.

The second law efficiency is also impacted by changes in the ambient temperature. In GETEM's calculations for binary plants, the ambient temperature is held constant. Its effect on performance, however, is captured in the net capacity factor that is used. This capacity factor accounts for both plant availability and the effect of the ambient temperature on power generation throughout the year (see Appendix A1).

GETEM determines the second law efficiency based on the geothermal conditions at the start of operation. In estimating power generation, this efficiency is corrected to account for changes in the geothermal temperature using a correlation that is based on changes in the Carnot efficiency. The Carnot efficiency is defined as:

$$Carnot\ efficiency = 1 - \frac{T_0}{T}$$

In this relationship, T_o is the assumed ambient temperature (kept fixed), and T is the geothermal temperature at a point in time; both are absolute temperatures in either °K or °R. The relationships between the second law efficiency and the Carnot efficiency that are used for both air-cooled binary and flash steam plants are based upon modeling that has been done of the performance of plants operating with fixed equipment (size and performance) at off-design conditions.

The following are the relationships used to determine how temperature decline (as represented by the Carnot efficiency) impacts the second law efficiency:

Binary Plants

$$\frac{eff}{eff_{design}} = -10.956\left(\frac{Carnot\ eff}{Carnot\ eff_{initial}}\right)^2 + 22.422\left(\frac{Carnot\ eff}{Carnot\ eff_{initial}}\right) - 10.466$$

Dual-Flash Steam Plants, T> 210°C

$$\frac{eff}{eff_{design}} = -9.5604\left(\frac{Carnot\ eff}{Carnot\ eff_{initial}}\right)^2 + 19.388\left(\frac{Carnot\ eff}{Carnot\ eff_{initial}}\right) - 8.8276$$

Dual-Flash Steam Plants, T≤ 210°C

$$\frac{eff}{eff_{design}} = -10.559\left(\frac{Carnot\ eff}{Carnot\ eff_{initial}}\right)^2 + 21.683\left(\frac{Carnot\ eff}{Carnot\ eff_{initial}}\right) - 10.124$$

Single-Flash Steam Plants, T> 240°C

$$\frac{eff}{eff_{design}} = -11.42747\left(\frac{Carnot\ eff}{Carnot\ eff_{initial}}\right)^2 + 22.89446\left(\frac{Carnot\ eff}{Carnot\ eff_{initial}}\right) - 10.467$$

Single-Flash Steam Plants, T≤ 240°C

$$\frac{eff}{eff_{design}} = -10.06859\left(\frac{Carnot\ eff}{Carnot\ eff_{initial}}\right)^2 + 20.13903\left(\frac{Carnot\ eff}{Carnot\ eff_{initial}}\right) - 9.07044$$

The flash steam plants have relationships that are functions of temperature because, as the resource temperature declines, at some point the lowest flash pressure can reach 1 atm. It is assumed that the operator will take steps to assure the plant does not operate with sub-atmospheric flash pressures.

The effect that the temperature decline has on conversion efficiency used is illustrated in Figure A-22.

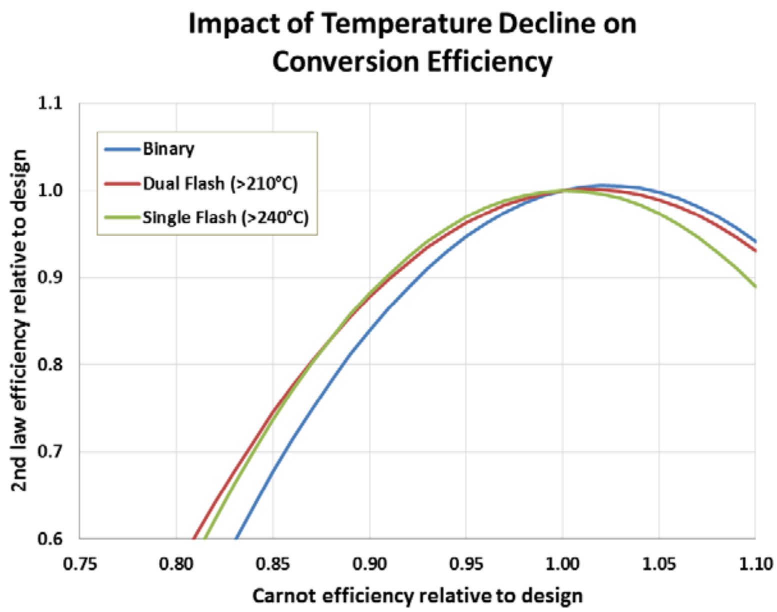


Figure A-22. The effect of temperature decline on conversion energy.

Power Output

As the resource temperature declines, the resulting effects on both available energy and conversion efficiency are used to estimate the plant power output. Figure A-23 illustrates the effect that the temperature decline rates shown in Figure A-21 have on both available energy and the estimated power generation for a 175° and 250°C resources. In Figure A-23, it is assumed that the 175°C resource uses an air-cooled binary power plant, while the 250°C resource uses a dual flash plant. The difference between the available energy (dashed lines) and the power (solid lines) represents the impact of the reduced conversion efficiency as the temperature declines.

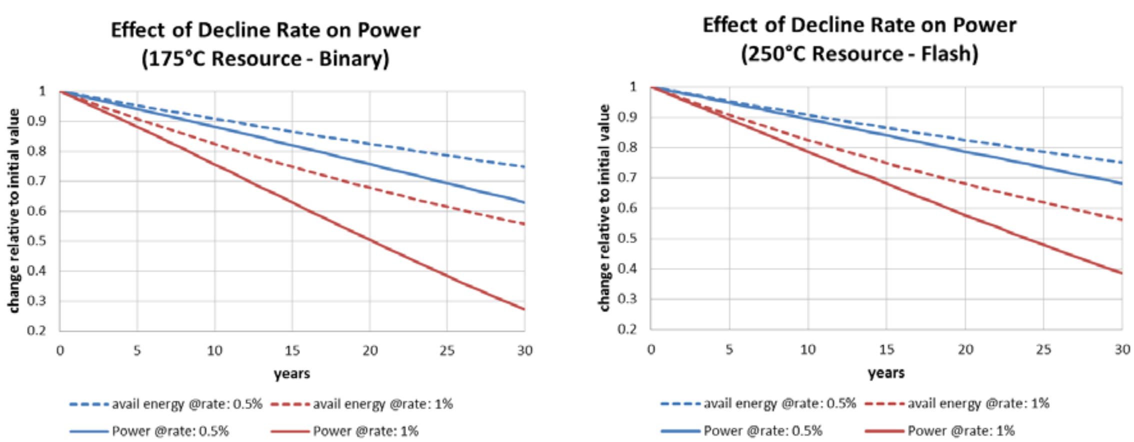


Figure A-23. The effect of temperature decline rate on both potential to produce power and power.

In GETEM power output is estimated at 12 evenly spaced intervals for every year of the project life. For each period, the geothermal temperature is determined, which is then used to determine both the available energy and the Carnot efficiency. The Carnot efficiency is used to determine the second law conversion efficiency. These values are then used to determine the net power output from the plant for that point in time.

$$net\ plant\ output_{time} = \eta_{II_{time}}(\dot{m}_{gf})(\dot{a}e_{time})(net\ capacity\ factor_{@design})$$

In this calculation, the geothermal flow rate (m_{gf}) and the *net capacity Factor* are those at the start of operation (design values).

This is the net output from the plant at a point in time. Power sales at that point are determined assuming that the geothermal pumping power remains unchanged with time. With this assumption and the assumption of a constant flow rate, the brine effectiveness based on sales is determined.

$$brine\ effectiveness_{time} = \eta_{II_{time}}(\dot{a}e_{time})$$

$$specific\ geothermal\ pumping\ power = \frac{(power_{production\ pump} + power_{injection\ pump})}{\dot{m}_{gf}}$$

$$brine\ effectiveness_{sales\ @\ time} = brine\ effectiveness_{time} - specific\ geothermal\ pumping\ power$$

Power sales at a point in time is determined by multiplying the brine effectiveness by the flow rate and net capacity factor:

$$power\ sales_{time} = brine\ effectiveness_{sales\ @time}(\dot{m}_{gf})(net\ capacity\ factor_{@design})$$

This calculation for sales is made at each defined interval over the life of the project. (For a 30-year project, the calculation is made 30 × 12, or 360 times.)

Makeup Drilling

As shown, the power output and sales decrease as the resource temperature declines. To offset the lost revenues, operators may drill makeup wells throughout operation of the facility. When this is done, wells may or may not be taken out of service. If they are not, the total geothermal flow rate increases. Because calculations are based on the premise of a constant flow, it is not possible to incorporate this common activity into the model. In lieu of providing for this type of makeup drilling, it is assumed that at some point in time, the entire well field (and with EGS, reservoir as well) will be replaced. At that time, the resource temperature returns to the original value and begins to decline anew at the same rate. GETEM allows this replacement to occur as long as sufficient resource potential was discovered at the developed site during the exploration phase and as long as the project is not in its last 5 years of operation.

The maximum allowable temperature decline is a specified input, with the default based on a curve fit of the end of life temperatures from the 1996 EPRI study (EPRI 1996). The maximum decline allowed is (in °C):

$$\Delta T_{gf} = 0.21 T_{gf-initial} - 12.2$$

This decline approximates a decline of 10% in the Carnot efficiency, corresponding to a replacement temperature of:

$$T_{replacement} = \frac{T_o}{\left[0.9 \times \left(\frac{T_o}{T_{initial}}\right) + 0.1\right]}$$

This expression for the replacement temperature uses absolute temperatures either in °K or °R. Once temperature declines exceed the maximum allowed, GETEM assumes the well field is replaced, assuming that the replacement criteria are met (i.e., sufficient resource potential and not in last 5 years of project). The calculations of the temperature decline and power output are done at 12 intervals per year in order to better capture the timing of the replacement on the LCOE. When it occurs, a replacement capital cost is included in the estimate of the LCOE. The benefit of the replacement, in terms of reducing the LCOE, will be tempered by the discount rate that is used to determine the present value of the both revenues from power generated and costs incurred over the project life.

The well field replacement costs include the following:

$$
\begin{aligned}
replacement\ cost \\
&= (production\ well_{count} + spare\ wells) \\
&\times (drilling\ cost + stimulaiton\ cost)_{production\ well} + injection\ well_{count} \\
&\times (drilling\ cost + stimulaiton\ cost)_{injection\ well} \\
&+ surface\ equipment\ cost_{production\ \&\ injection\ well} + pump\ cost_{production\ wells} \\
&+ indirect\ cost
\end{aligned}
$$

The production well count is the number of successful production wells required; the injection well count is the number of wells used for injection. This count includes any failed wells that are used to supplement injection. If failed wells are not used to supplement injection, the injection well count is the number of successful injection wells required. Indirect costs are determined using the same approach used in determining pre-operation capital costs. Overnight capital cost estimates or inputs are used, with no inflation applied. Makeup drilling is considered a replacement capital cost with the 5-year MACRS depreciation schedule applied.

Injection pumps (if used) are not replaced; they are assumed to be located at the power plant. Leasing and permitting costs are also not included in the replacement costs; it is assumed those costs are incurred at the beginning of the project.

Application of Approach

This approach for estimating power was applied to production data from operating facilities to assess whether the estimates being provided could be considered reasonable.

Binary Facility

The basic approach used to estimate the impact of resource temperature decline on power production in GETETM was used to estimate the power production from an operating facility over an extended period of operation. The estimated output was based upon the flow rate, resource temperature, and power output taken early in the plant's operation once flow rate had stabilized. For this calculation, the average ambient air temperature used was based on data from a nearby weather station. The geothermal temperature after a period of 13 years of operation was used to establish an annual decline rate of ~0.7%. This decline rate, the initial conditions, and a net capacity factor of 95% was used to estimate the power generation over the 13 years. That estimate is shown below in Figure A-24 along with the reported generation. The fluctuations in the reported power represent the changes in power generation occurring from summer to winter. The estimated value shown does not have those fluctuations because of the constant ambient temperature used when determining the available energy. (The variation in the estimated generation is due to the changes in the number of days in between months.)

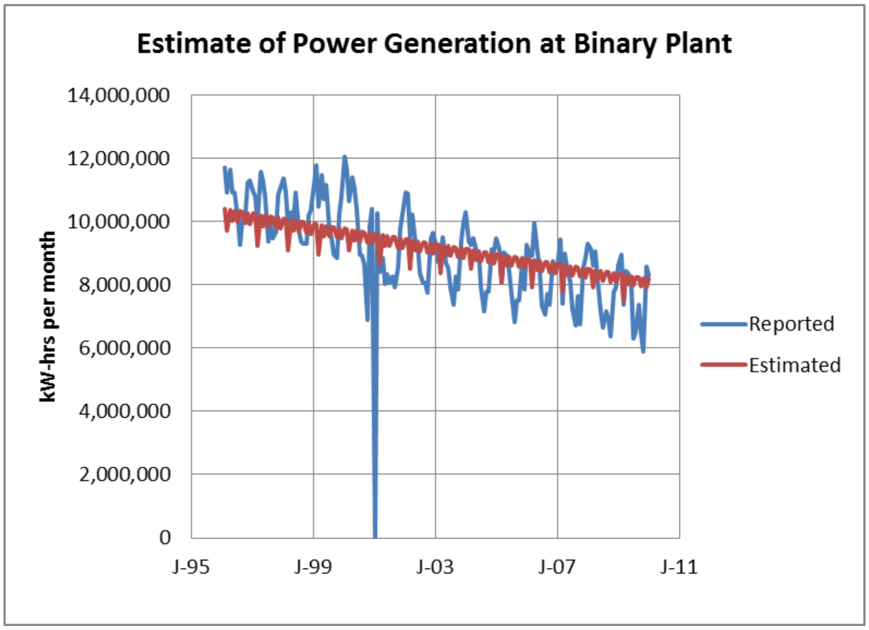


Figure A-24. Comparison of estimated and reported power generation at a Nevada binary plant.

Over this period, the total MW-hrs of generation differed by ~1%, with the total estimated power being higher than that reported, though it should be noted that, over this period, the total flow used for the estimate was ~4.5% higher than the total reported flow.

This calculation was repeated with the estimated generation based on the average monthly temperature from the nearby weather station. These temperatures were used to estimate the geothermal fluid's available energy and conversion efficiency. Those values and the reported flow were used to estimate the monthly output shown in Figure A-25 below.

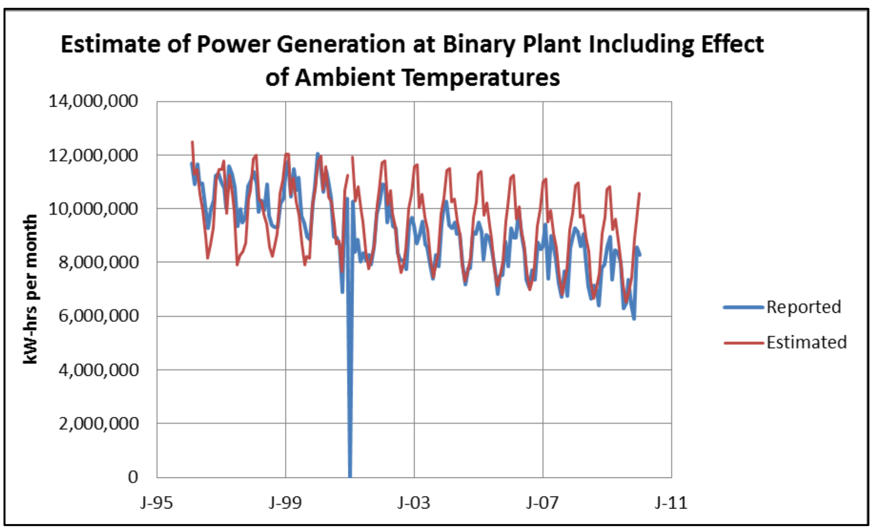


Figure A-25. Comparison of reported and estimated power generation when including effect of ambient temperatures.

Using this approach, the estimated output exceeded the reported output by ~4.8% when totaled over the 13-year period (with effectively a constant geothermal flow rate). As suggested by this figure, the estimated output was consistently higher during winter operation. This might reflect the operator curtailing the winter operation, to keep from exceeding the maximum generator capacity or to maintain the condenser at a pressure above 1 atmosphere; it is suspected that the latter may have occurred.

The approach was applied to a second binary plant. At this plant, the annual decline rate was determined to be ~0.44%. Figure A-26 below shows the estimated output versus the reported output from the plant over a period of stable operation. At this facility, the operator began to increase flow early in the operation of the plant; over this period, the flow was increased by ~25%. This appears to have been done, at least in part, to offset the effect of the temperature decline. As shown with the assumption that the flow rate remained fixed (at initial conditions), the approach used in GETEM estimated a power output below that reported. A relationship was developed between change in flow and time, which was applied to the estimate. By including the increasing flow into the estimate, the agreement between the estimate and the reported output improved.

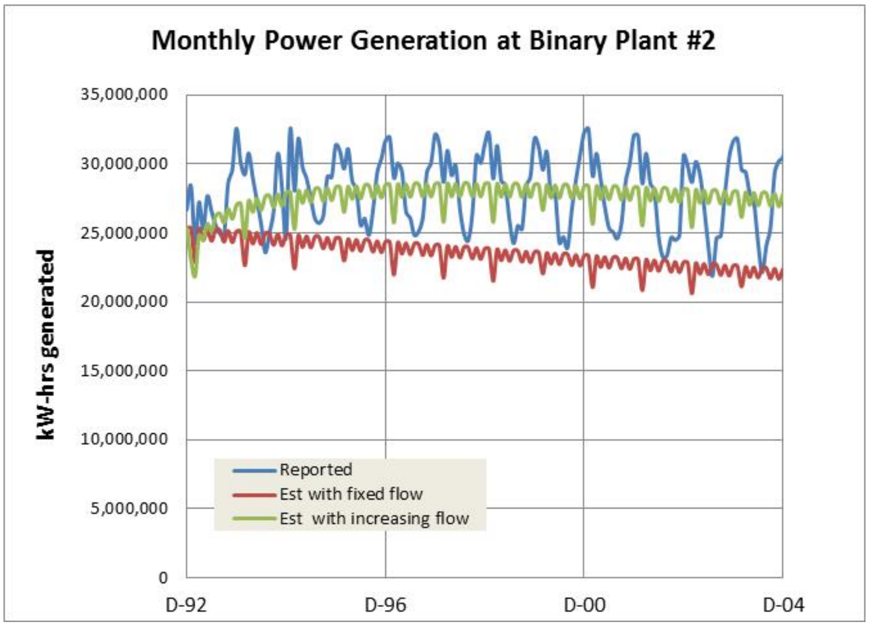


Figure A-26. The estimate output versus the reported output at second Nevada binary plant.

Generally increasing the geothermal flow rate will adversely impact the power cycle's second law conversion efficiency. This effect is not included in the estimate shown. If it had been, it is believed that the agreement between the estimated power and reported power would have improved relative to what is shown.

Flash Plant

A similar approach was applied to a flash steam power plant. At this facility, the annual temperature decline rate was determined to be ~0.6%. With this decline rate and an average annual wet bulb temperature based on data from a nearby weather station, the output was estimated for an 8-year period using the initial geothermal conditions and plant performance at design conditions. Figure A-27 below shows both the estimated and reported output for this plant.

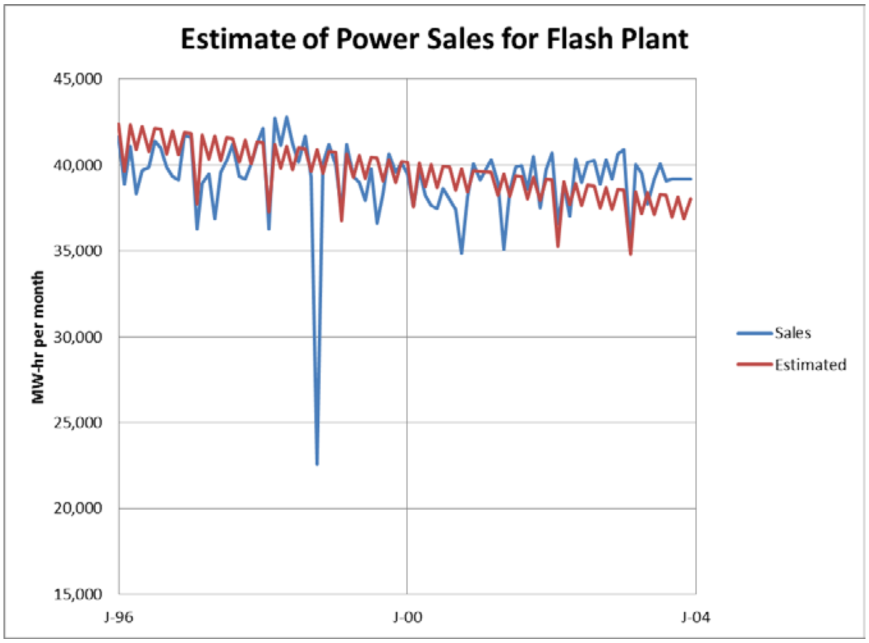


Figure A-27. Estimated and reported output for Nevada flash plant.

Over this period, the total estimated output was ~1% higher than the reported output. The total flow over this period used in the estimate was ~1.5% higher than the reported flow rate.

The comparison of the estimated generation with the actual generation at existing facilities indicates the approach used in GETEM provides a reasonable representation of the reported generation, especially if the geothermal flow rates from those facilities have little variation with time. Though this approach is based on a fixed flow rate and ambient temperature, it can depict both the effect of seasonal variations in power generation and the effect of a varying geothermal flow rate, providing reasonable approximations of the power produced from the operating plants.

Makeup Water

Though the scenarios that are assumed to require makeup water are for EGS resources, GETEM also allows for evaporative losses from hydrothermal flash plants to be made up. It is assumed that there is a cost for this makeup (whether EGS or hydrothermal) that is included as an O&M cost in the determination of the LCOE. There is also a cost in terms of the effect that this additional injectate has on geothermal pumping power, which in turn impacts the size of the power plant and well field needed for a specified level of power sales.

The subsurface water loss for EGS resources is a specified value. The default is 5% of the injection flow. Though the loss is a fraction of the injection flow, it is determined from the production flow using the following relationship:

$$subsurface\ loss = production\ flow \times \left[\frac{1}{(1 - loss\ rate)} - 1\right]$$

$$injection\ flow_{EGS} = production\ flow + subsurface\ loss$$

As an example, if the production flow is 100 kg/s, for the default loss rate of 5%, the subsurface water loss would be 5.26 kg/s. The total flow injected would be 105.26 kg/s. The injection pumping power for EGS resources is based on the flow rate that includes the subsurface losses.

It is assumed that flash steam plants utilize evaporative heat rejection systems where the steam condensate is utilized for cooling tower makeup. The estimated water loss in an evaporative heat rejection system is discussed in Appendix A11. With EGS resources using flash steam plants, this evaporative loss must be made up. As indicated, this makeup is an option for hydrothermal resources using flash plants. When this option is selected for hydrothermal resources, the injected flow is always equal to the produced flow. The O&M cost (see Appendix A10) is the product of the unit cost of the makeup water and the total makeup water required.

Flow in Production and Injection Intervals

In determining the geothermal pumping power, the pressure change across the production or injection interval is based on fluid flow and velocity being constant through the entire length of the interval (i.e., the total flow enters or leaves the well at a single point [the defined resource depth]). This results in a conservative definition of the pumping power; it is the default for hydrothermal resources. With the EGS resource default, fluid enters (or leaves) the production (or injection) interval along the entire length of the interval. The amount of fluid flow in the well bore decreases with depth and is defined at any point in the interval as:

$$m_{gf\ @L} = m_{top\ of\ inerval} \times \frac{L}{L_{interval}}$$

In this relationship, the length (L) is measured from the bottom of the interval (well), with the flow at the top of the interval being the produced or injected well flow. If the interval has a constant diameter and the density does not change, this relationship can be expressed in terms of velocity.

$$V_{@L} = V_{top\ of\ interval} \times \frac{L}{L_{interval}}$$

The pressure or head loss due to friction is determined as:

$$head\ loss = \frac{f}{D} \times L \times \frac{V^2}{2 * g} = \int_0^{L_{interval}} \frac{f}{D}\left(\frac{V^2}{2 * g}\right) dL$$

Substituting the expression for velocity as a function of L and solving, the head loss is:

$$head\ loss = \frac{f}{D * 2g} \times V_{top\ of\ interval}{}^2 \times \frac{total\ length}{3}$$

This yields a pressure loss that is one-third of that obtained if the flow and velocity are constant along the entire length of the interval. This approach is intended for use when there are multiple fractures or points of fluid entry or exit in a well.

A10: OPERATION AND MAINTENANCE COSTS

The Operations and Maintenance (O&M) costs that contribute to the LCOE reported in GETEM include:

- Labor
  - Plant
  - Field
- Maintenance
  - Plant
  - Wells/reservoir
  - Gathering system
  - Production pumps
- Makeup water
- Taxes and insurance
- Royalties.

Based on discussions with industry, it is expected that these O&M costs will contribute \$0.015 to \$0.035 per kW · h to the LCOE.

Labor

The estimated facility staff size is dependent upon the type and size of the power plant. The estimate is based on observations made at different operating facilities over the period from 1995 to 2005 by the original contributors to the development of GETEM. In early versions of the model, the labor estimates were table lookups. This resulted in "step" changes in costs and LCOE, and the estimates were revised with the staff for operations, maintenance, and technical/office support currently determined for each type of plant as a function of its size.

Operation personnel are assumed to be present continuously, with the estimate of the staffing required is for a single shift determined using the following relationship:

$$\#\, operators_{shift} = 0.25(plant\ size_{MW})^{0.525} + 0.1(\#modules - 1)^{0.625}$$

The estimate is the same regardless of the plant type, and is adjusted upward, as indicated, if the plant is comprised of modular units.

The level of staffing for maintenance activities is based on the plant type, with more personnel estimated for binary plants under the premise that these facilities are more equipment intensive. (This is consistent with informal observations made by GETEM's original developers at operating plants.) The estimate for maintenance staff includes three categories: welder/mechanic, electrician/instrument technician, and general maintenance. For each plant type, it is assumed that there is an equal number personnel for of each maintenance category.

Binary:

$$\#\, maintenance_{category} = 0.15(plant\ size_{MW})^{0.65} + 0.05(\#modules - 1)^{0.625}$$

Flash:

$$\#\, maintenance_{category} = 0.13(plant\ size_{MW})^{0.65} + 0.05(\#modules - 1)^{0.625}$$

Again, this is for each of the three maintenance categories identified.

The staffing for technical support is the same for both plant types. It is a function only of the plant size. This support includes three categories: facility manager/engineer, operations management, and clerical/office. It is assumed that the level of support is equal for each of these three categories.

$$\#\ technical\ support_{category} = 0.075(plant\ size_{MW})^{0.65}$$

The annual man-hours for operations personnel is the product of number of operators per shift and the total hours in a year (8,760). The annual hours for each of the categories for both maintenance activities and technical support is the product of the number of staff for each category and an assumed 2,000 hrs for a year.

A direct labor rate is assumed for operators and each category for both maintenance and technical support. These values were defined in 2004, and are adjusted to the year for which the LCOE estimate is made using a producer price index for labor. A multiplier of 1.8 is applied to the labor cost to include indirect costs for benefits, overhead, home office, and similar costs. The rates used are summarized in Table A-6 below.

Table A-6. Hourly rates used to determine labor costs.

Staff	Direct Labor Rate (2004 Dollars)
Operator	$20/hr
Welder/Mechanic	$24/hr
Electrician	$24/hr
General Maintenance	$17.50/hr
Facility Manager/Engineer	$40/hr
Operations Manager	$30/hr
Office/Clerical	$12/hr

The labor rates and categories for O&M staffing are subjective. It is probable that operating plants will have varying blends of staff capabilities, with some of the staff providing support in several areas. These estimates attempt to be representative of a typical staff composition.

GETEM does not provide an option to change the labor rates, the labor multiplier, or the type of personnel used; rather, the number of staff can be adjusted to revise the total labor cost.

In using the discounted cash flow method to determine the LCOE, the contribution of the O&M labor to the LCOE is reported as a single value. When the fixed charge rate method is used, a portion of the labor costs (25% of the operations labor) is attributed to the well field. The remaining labor costs are provided in the plant O&M contribution to the LCOE.

Maintenance

Power Plant

The annual maintenance costs for the power plant are determined as a fraction of the total capital cost for the power plant. That default input for this value is 1.8% of the capital cost. The default is the same for both flash and binary plants.

Because the flash plants are assumed to utilize evaporative cooling systems, they are assumed to have an O&M cost associated with the treatment of the cooling water. There has been little information available upon which to estimate these costs. They are determined in GETEM using an approach based on information in a report prepared by Tetra Tech in 2008 that examined the modification of power plants in California from using cooling systems to using cooling towers. This document indicated that costs for fouling and corrosion control would be \$1.40 to \$2.03 per gpm of cooling water flow (Table 5-2 from this document); a midpoint cost of \$1.70/gpm is used as the default input (in 2007 dollars). This is the default used with GETEM's estimate of cooling water flow rate to determine an annual chemical cost for the power plant.

$$annual\ plant\ chemical\ costs = cooling\ water\ flow\ (gpm) \times treatment\ cost\ (\frac{\$}{gpm})$$

A PPI for industrial chemicals is applied to bring costs to the year for which the LCOE is being estimated.

This is a recent change to GETEM, replacing previous placeholders for this cost. The values estimated with this methodology are lower than those previously estimated. This treatment cost is inherent to GETEM's calculation and cannot be revised by anyone other than GTO.

Well Field and Gathering System

The annual maintenance costs for the wells and surface piping are also determined as a fraction of the capital cost for the well field and gathering system, including any well stimulation that is done. Only the costs of wells supporting the operation of the plant are used; costs of failed wells are not included unless used to supplement injection. The default for this inputted value is 1.5% of the capital cost, with the same default used for both flash and binary plants. These costs are for maintaining the surface equipment and injection pumps, and for work done on the wells and reservoir to maintain productivity. It does not include any makeup well drilling.

Because binary plants are assumed to have production pumps and to operate with minimum temperature constraints to prevent mineral precipitation, there are no brine chemical treatment costs included in the O&M costs for these plants. For flash plants, a treatment cost is included. There is minimal information available to estimate this cost, in part because of the variability in geothermal fluid chemistries. GETEM's default for this cost is taken from Gallup's 2005 *Geothermics* paper. The mean values to treat 1,000 tonnes of brine is \$22.50 (Table 2 in this paper), in 2005 dollars. GETEM's estimate of the flow required to produce a specified level of sales is used with this value to determine the default annual brine treatment cost.

$$annual\ brine\ chemical\ costs = annual\ geothermal\ flow\ \left(\frac{kg}{yr}\right) \times chemical\ cost(\frac{\$}{1{,}000\ tonnes\ of\ geothermal\ fluid})$$

This cost is adjusted to the year for which GETEM is estimating the LCOE using a PPI for industrial chemicals.

This is also a recent change, replacing the previous placeholders used to estimate this cost. The resulting annual cost is higher than obtained with the placeholders. This is not a GETEM default input that can be revised. If it needs to be changed, the maintenance cost multiplier for the well field can be used to adjust the total O&M cost for the well field.

Production Pumps

The costs to maintain the production pumps is not included in the maintenance cost determined for the well field and surface equipment. These pumps are periodically replaced or taken out of service and re-built. The default is the use of a line-shaft pump, which is assumed to have a longer operating life (3 years) than an electric submersible pump (2 years). At the end of the life, the pump is removed and replaced. There is no additional cost for the pump casing, but there are time and cost requirements for the removal and installation of the new pump.

$$pump\ cost_{replacement} = pump\ cost + installation\ cost_{per\ ft}\left(depth_{setting}\right) + workover\ rig\ for\ 1\ day$$

There is no built-in schedule for pump replacement. Instead, it is assumed that a fraction of total pumps in service will be replaced each year as indicated in the relationship below for the annual maintenance costs.

$$annual\ pump\ cost_{replacement} = pump\ cost_{replacement} \left(\frac{\#pumps\ in\ service}{pump\ life\ in\ yrs} \right)$$

Line-shaft pumps will have an annual cost for the lubricant used for the shaft bearings. The placeholder values previously used to determine this cost have been revised. Little information has been published on the amount of oil needed to lubricate a pump. The placeholders related the consumption of oil to the brine flow rate. It is more probable that the consumption will be related to the pump setting depth. A GRC paper (Price and Burleigh 2001) provides a cost of $4,300 annually for a pump with a setting depth of 500 ft. This information was incorporated into the following relationship to estimate the annual oil cost per line-shaft production pump:

$$annual\ cost_{oil} = SF \times annual\ cost_{reference-oil}$$

if pump setting depth =0, $SF = 0$

if pump setting depth <250 ft, $SF = 0.5$

if pump setting depth $\geq$250 ft, $SF = {}^{\text{pump setting depth}}/_{\text{reference depth.}}$

In these relationships, the reference setting depth is 500 ft and the reference annual cost is $4,300 (both values from Price's paper). It is probable that some minimum amount of oil will be required regardless of the depth, and, though it is somewhat arbitrary, setting the scaling factor (*SF*) to 0.5 for depths less than 250 ft captures this minimum requirement. The reference annual oil cost of $4,300 per pump is in 2001 dollars. That value is adjusted using the PPI for refined petroleum products. These costs and reference depth are not default values that can be revised.

Makeup Water

Discussion on the determination of the amount of water that must be made up annually is provided in both Appendix A9 and Appendix A11. Costs for water are dependent upon both location and the quality of the water required. A report from Sandia National Laboratory (Tidwell 2013) used a cost of $0.35 per kW · h, which is the energy cost to lift, move, and treat water. If the makeup water has to be lifted 250 ft, then the energy cost for 1 acre-ft of water would be ~$146. In the western states (exclusive of California), the cost for appropriated and unappropriated ground water ranges from $16 to $250 per acre-ft. This cost and the energy cost to deliver the water are the basis of GETEM's default of $300 per acre ft for makeup water for hydrothermal flash and EGS binary plants.

It is postulated that, when using flash plants with EGS resources, a higher-quality makeup water will be required. This is based on the premise that if flashed steam condensate is used as makeup for heat rejection, a similar-quality water will be needed to replace this fluid. If not, it is possible that the concentration of dissolved solids in fluid circulating through the EGS reservoir will increase with time, leading to potential operational problems both in the surface facilities and the subsurface reservoir. The Sandia report indicates that the cost of using brackish groundwater is in the range of $1,500 to $2,000+ per acre ft. This cost includes well drilling and RO treatment to provide the desired water quality. This is the basis for GETEM's default of $2,000 per acre-ft for makeup water for EGS flash plant scenarios. There are no PPIs applied to water costs.

Taxes and Insurance

Taxes refer to property taxes, not sales taxes on revenue. The annual taxes and insurance costs are determined as a specified fraction or percentage of capital costs. The capital costs used are the plant cost and the cost of the wells and surface equipment that support plant operation. (Any stimulation costs associated with the wells are also included). Costs of failed wells, or costs at sites not developed, are not included.

The default for this annual tax and insurance rate is 0.75%. This value is based on the industry interviews by GTO's LCOE analysis team.

Royalties

GETEM assumes that royalties are paid per the BLM royalty schedule, in which the royalty payments for the first 10 years of operation are 1.75% of revenues. After 10 years, royalties are 3.5% of revenues.

This rate schedule was taken from 2007 Federal Register 43 CFR, Part 3200.

A11: POWER PLANT

Different methodologies are used in estimating the costs and performance of air-cooled binary and flash steam power plants. The ability to select different working fluids and varying process conditions within the binary cycle provides an additional degree of freedom in designing air-cooled binary plants. This added degree of design flexibility requires an alternative approach in GETEM when determining plant cost and performance of projects using air-cooled binary plants.

The following discussions provide detail as to how plant performance and cost are determined for both types of power plants.

Flash Steam Plants

Flash Conditions

Either single-flash or dual-flash power plants can be evaluated. While there has been a recent installation of a triple-flash plant, that configuration is not a current option in GETEM. Unlike the air-cooled binary plants, which are characterized in GETEM based on a fixed ambient temperature of 10°C, a design wet bulb (heat sink) temperature can be specified for the flash plant. Inherent to the flash plant calculations are default inputs for the cooling water temperature rise and approach temperatures in both the cooling tower and the condenser. The values used are representative of a limited number of plants for which information was available; they are default inputs that cannot be revised. The default values for the approach temperatures and cooling water temperature rise are used with the specified wet bulb temperature to determine a condensing temperature. The condensing temperature and the specified resource temperature are used in an approach described by DiPippo (2012) to find near optimal flash-separator temperatures. DiPippo refers to this approach as the “equal-temperature-split” rule, in which the temperature range between the resource temperature and condenser is divided into equal segments. The number of segments is equivalent to the number of flash plus one. These flash temperatures (defined below) represent the final temperature (and pressure) in the flashing process, in which the steam vapor is separated from the unflashed liquid.

$$T_{single\ flash} = \frac{(T_{resource} - T_{condenser})}{2}$$

$$T_{HP-dual\ flash} = T_{resource} - \frac{(T_{resource} - T_{condenser})}{3}$$

$$T_{LP-dual\ flash} = T_{resource} - 2 \times \frac{(T_{resource} - T_{condenser})}{3}$$

In these relationships, HP refers to the higher-pressure flash and LP to the lower-pressure flash. The condenser temperature is determined as:

$$T_{condenser} = T_{wet\ bulb} + \Delta T_{cooling\ tower\ approach} + \Delta T_{cooling\ water} + \Delta T_{condenser\ approach}$$

The flash temperatures determined represent the near optimal turbine inlet condition (saturated vapor at these temperatures). In the operation of a flash plant, constraints may be imposed that preclude operation at these conditions. One constraint on operation is that the steam pressures upstream of the turbine be greater than one atmosphere to prevent air leakage into the steam. (This leakage would add to the non-condensable gases that must be removed from the condenser.) This constraint is more likely to occur with dual-flash plants (which are the GETEM default). Using the approach described, this limit would be reached for the low-pressure flash at resource temperatures less than 230°C, assuming a condenser temperature of 35°C; with a 40°C condensing temperature, the limit would be reached for resource temperatures less than 220°C.

Another constraint placed on temperature would be to prevent mineral precipitation; in GETEM, a constraint is imposed to prevent precipitation of amorphous silica.

Because the flashing process concentrates the silica in the remaining liquid phase, the solubility temperature of amorphous silica in that liquid increases. The relationship used to relate temperature (°C) to silica concentration is discussed in Appendix A12 and is shown here:

$$T_{qAmorphous\ silica} = 2.49634 \times 10^{-11}\left(SiO_{2_{quartz}}{}^{4}\right) - 4.25191 \times 10^{-9}\left(SiO_{2_{quartz}}{}^{3}\right) - 1.19669 \times 10^{-3}\left(SiO_{2_{quartz}}{}^{2}\right) \quad + 0.307616\left(SiO_{2_{quartz}}\right) - 0.2944$$

The silica concentration in the remaining liquid phase after a flash is:

$$SiO_{2_{liquid-out}} = \frac{SiO_{2_{resource}}}{\left[1 - x_{HP\ flash} - x_{LP\ flash}\left(1 - x_{HP\ flash}\right)\right]}$$

In this relationship, x_{flash} is the fraction of steam that has been generated. It would be defined as:

$$x_{flash} = \frac{\left(h_{in} - h_{f_{flash}}\right)}{\left(h_g - h_f\right)_{flash}}$$

In this relationship,

h_f is the enthalpy of a saturated liquid at the lowest flash temperature

h_g is the enthalpy of a saturated vapor at the lowest flash temperature

h_{in} is the enthalpy of a saturated liquid at the resource temperature, or entering the LP flash vessel.

Solving for a flash temperature that is equivalent to the solubility temperature of amorphous silica can be done iteratively using the above relationships. Because of the property limitations in GETEM, a relationship is used that approximates this solution.

$$T_{SiO2\ limit_{flash}} = 1.61869 \times 10^{-4}\left(T_{resource}{}^{2}\right) + 0.83889\left(T_{resource}\right) - 79.496$$

The effect that flashing has on the solubility temperature is shown in Figure A-28 below based on the relationships used in GETEM to determine the solubility temperature of amorphous silica. The curve for no flashing is representative of the limits that would be imposed on a binary plant.

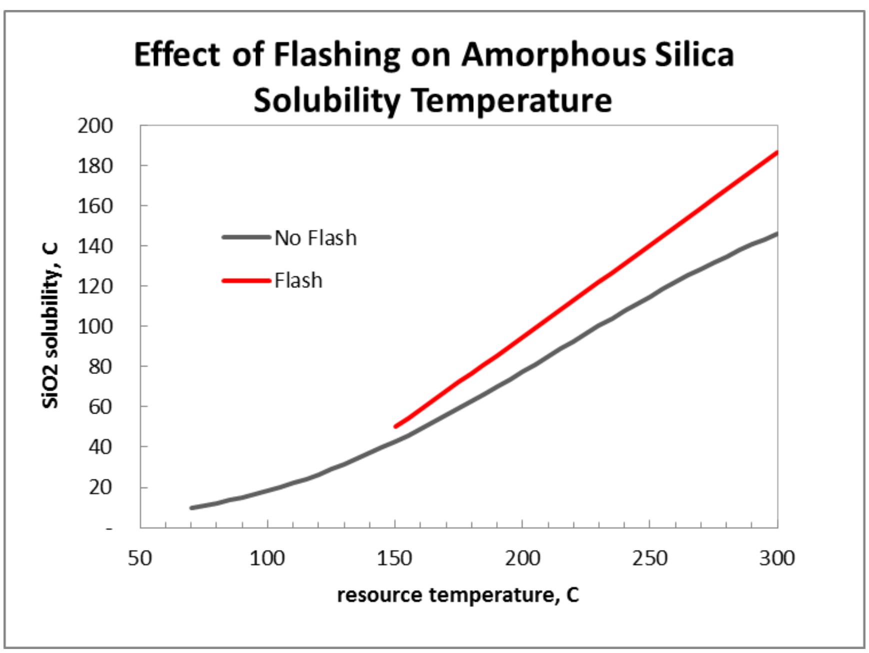


Figure A-28. Effect of flashing on amorphous silica solubility temperature.

In establishing the flash temperatures used, the optimal flash temperature for the low-pressure flash (or the single-flash temperature) is compared to the temperature constraints imposed by a 1 atm minimum flash pressure and the amorphous silica solubility temperature determined for the unflashed brine. The highest of these temperatures is used as the flash temperature. The temperature for the high-pressure flash is halfway between this temperature and the temperature of the geothermal resource.

Note that it is assumed that the production wells that supply the flash plant are not pumped. If the estimated wellhead pressure is less than the flash pressure determined, a warning occurs. Regardless of the warning, the flash pressure determined by the approach described above is used to determine the plant performance and cost.

In an operating plant, there will be a frictional pressure drop between the separator vessel and the turbine. The optimal temperatures and a default pressure drop are used to determine the flash-separator pressures.

$$P_{1st\ flash} = P_{saturation_{@T_{1st\ flash\ optimum}}} + \Delta P_{friction}$$
$$P_{2nd\ flash} = P_{saturation_{@T_{2nd\ flash\ optimum}}} + \Delta P_{friction}$$

In these relationships, $P_{1st\ flash}$ is the pressure in a single-flash plant, or in a dual-flash plant, it is the higher flash pressure. $P_{2nd\ flash}$ is the lower pressure in a dual-flash plant. The default pressure drop is 1 psi; this is not a model input that can be revised.

Steam Flow

With the determination of the flash-separator pressures, the fraction of steam produced by each flash can be determined.

$$x_{1st\ flash} = \frac{\left(h_{resource} - h_{f_{@P_{1st\ flash}}}\right)}{\left(h_g - h_f\right)_{@P_{1st\ flash}}}$$
$$x_{2nd\ flash} = \frac{\left(h_{f_{@P_{1st\ flash}}} - h_{f_{@P_{2nd\ flash}}}\right)}{\left(h_g - h_f\right)_{@P_{2nd\ flash}}}$$

where

h_f is the enthalpy of a saturated liquid at the indicated pressure

h_g is the enthalpy of a saturated vapor at the indicated pressure

$h_{resource}$ is the enthalpy of a saturated liquid at the resource temperature.

The steam flow from each flash is determined as:

$$\dot{m}_{steam_{1st\ flash}} = x_{1st\ flash}\left(\dot{m}_{gf-in}\right)$$
$$\dot{m}_{steam_{2nd\ flash}} = x_{2nd\ flash}(1 - x_{1st\ flash})\left(\dot{m}_{gf-in}\right)$$

The determination of plant performance in GETEM is based on a fixed geothermal flow (m_{gf-in}) of 1,000 lb/hr into the plant. This flow rate is arbitrary, but allows the plant performance to be determined on a per-unit-mass basis. Once this performance metric is known, the specified power sales can be used to determine the total geothermal flow required and the equipment sized.

Non-Condensable Gas Removal

During the flashing process, dissolved gases will come out of the solution and expand with the steam through the turbine. While the work done in expanding these gases is not estimated, the work required to remove the gases from the condenser is estimated. The removal system in GETEM is a hybrid system, with the first two stages using steam ejectors and final 3rd stage using a vacuum pump.

The amount of non-condensable gases in the geothermal fluid is specified as a fraction (ppm by mass).

$$\dot{m}_{ncg} = x_{ncg}(m_{gf-in})$$

While all of the non-condensable gases are removed from the condenser, they are allowed to accumulate in the plant's main steam condenser until their partial pressure reaches a limit defined as:

$$P_{ncg} = 0.0000825(x_{ncg}) + 0.15\,,$$

where

P_{ncg} is the partial pressure of the gases in inches Hg, and

x_{ncg} is the gas concentration in ppm by mass.

This relationship is representative of information from a limited number of operating plants. The turbine exhaust pressure (and condenser pressure) used is the sum of the saturation pressure of water at the condenser temperature determined and the partial pressure of the non-condensable gases:

$$P_{turbine\ exhaust} = P_{condenser} = P_{saturation\ @\ T,condenser} + P_{ncg}$$

This partial pressure is also used to determine the amount of water vapor removed with the non-condensable gases:

$$\dot{m}_{water_{removed}} = \dot{m}_{ncg}\left(\frac{P_{saturation\ @\ T,condenser}}{P_{ncg}}\right)\left(\frac{\text{Mol Wt}_{water}}{\text{Mol Wt}_{ncg}}\right)$$

It is assumed that the molecular weight *(Mol Wt)* of the non-condensable gases is that of carbon dioxide (44 g per mole).

The amount of vapor removed from the condenser is the sum of the water vapor and the non-condensable gas, or:

$$\dot{m}_{removed} = \dot{m}_{ncg}\left[1 + \left(\frac{P_{saturation\ @\ T,condenser}}{P_{ncg}}\right)\left(\frac{\text{Mol Wt}_{water}}{\text{Mol Wt}_{ncg}}\right)\right]$$

A three-stage removal system is inherent to the calculations. It is assumed that the pressure ratios across each stage are equivalent, where

$$\text{pressure ratio}_{stage} = \frac{P_{discharge}}{P_{suction}} = e^{\frac{\ln\left(1\text{ atm}/P_{condenser}\right)}{\#\text{stages}}}$$

A condenser at the exhaust of each stage is used to recover steam condensate from the vent stream and reduce the flow to the subsequent stage; by reducing flow, the energy requirements for the next stage are reduced. The condensers for each stage operate at the same temperature as the main plant steam condenser, allowing the partial pressure of the non-condensable gases in a given stage condenser to be determined.

$$P_{ncg_{stage}} = \text{pressure ratio}_{stage} \times (P_{suction}) - P_{saturation\ @\ T,condenser}$$

The $P_{suction}$ term in this relationship is the discharge pressure from the previous stage, or for the first stage of the removal system, it is the condenser (turbine exhaust) pressure.

The partial pressure for a stage is used to determine the amount of vapor that is removed by the subsequent stage.

$$\dot{m}_{\text{removed}_{\text{next stage}}} = \dot{m}_{\text{ncg}}\left[1+\left(\frac{P_{\text{saturation @ T,condenser}}}{P_{\text{ncg}_{\text{stage}}}}\right)\left(\frac{\text{Mol Wt}_{\text{water}}}{\text{Mol Wt}_{\text{ncg}}}\right)\right]$$

Because the non-condensable partial pressure increases in each successive stage, the amount of water vapor in the vent stream is reduced, as is the energy required for that stage.

The steam ejectors used for the first two stages utilize the highest-pressure steam available. The methods used to establish the steam required were adapted from the performances curves for single stage ejectors in *Perry's Chemical Engineer's Handbook* (Green). Correlations developed from these performance curves are used to determine the mass ratio between the suction gas (condenser vent stream) and the motive gas (steam from the highest-pressure separator). The basic methodology is given below.

- Determine pressure ratio of vent gas to the motive steam (PR_m) through the following:

$$\text{PR}_{\text{m}} = \frac{P_{\text{saturation @ T,condenser}} + P_{\text{ncg}}}{P_{\text{HP flash}}}$$

- Determine the optimum area ratio (AR) for the nozzle using this motive pressure ratio and the stage pressure ratio:

$$\text{AR} = \left(3.5879\left(\text{pressure ratio}_{\text{stage}}{}^{-2.1168}\right)+1\right)\text{PR}_{\text{m}}{}^{\left(-1.155\left(\text{pressure ratio}_{\text{stage}}{}^{-0.0453}\right)\right)}$$

- Determine the uncorrected entrainment ratio (ER_u) using this area ratio and the motive pressure ratio:

$$\text{ER}_{\text{u}} = \text{PR}_{\text{m}}{}^{\left(2.9594\left(\text{AR}^{-0.8458}+0.99\right)\right)} \times [1.0035(\text{AR}) + 8.9374]$$

- This entrainment ratio is corrected to account for temperature and molecular weight differences (temperatures are in absolute units, in °R). The molecular weight of the vent stream is based on the composition of the stream at the ejector suction:

$$\text{entrainment ratio} = \text{ER}_{\text{u}}\left[\frac{T_{\text{steam}}(\text{Mol Wt}_{\text{vent stream}})}{T_{\text{condenser}}(\text{Mol Wt}_{\text{water}})}\right]^{0.5}$$

- From this entrainment ratio, the steam flow for the stage is determined:

$$\text{steam flow}_{\text{stage}} = \frac{\dot{m}_{\text{removed}_{\text{stage}}}}{\text{entrainment ratio}}$$

This calculation is made for each ejector stage, with the motive pressure ratio decreasing with each successive stage. The total steam required is the sum of that steam required for the first and second stages of the removal system. All steam required for NCG removal is provided by the highest-pressure flash/separator.

For the last (third) stage, a vacuum pump is utilized. The vent flow rate is that leaving the second stage condenser. The head is determined based on the pressure difference between 1 atm and the second stage pressure, and a density that is based on the pressure, temperature, and molecular weight of the vent stream at the pump suction. The default vacuum pump efficiency (η) is 70%.

$$\text{power}_{\text{vacuum pump}} = \frac{\dot{m}_{\text{vent stream}}\left(\Delta P_{\text{3rd stage}}\right)}{\eta_{\text{vacuum pump}}\left(\rho_{\text{vent stream}}\right)}$$

There is also a power requirement to bring the liquid condensate from each stage condenser to 1 atmosphere. For the first and second stage, the liquid condensate includes the motive steam for the ejector and a portion of the water vapor that enters the ejector with the non-condensable. The default efficiency used for these condensate pumps is 75%.

Steam Turbine

The performance of the steam turbine is determined using the approach defined by DiPippo (2012) for a single-flash turbine. This is done for both a single-flash and a dual-flash plant. For the dual-flash plant, turbine performance is based on the assumption that it can be approximated by using two turbines, one operating with the high-pressure steam at the inlet and the other with the low-pressure steam at the inlet. This differs from DiPippo's method for a dual-flash plant where the high-pressure steam expands to the lower flash pressure in the first stage of the turbine. This steam is then mixed with the low-pressure steam and expanded to the final exhaust pressure. Because the steam exhausting the first stage is "wet" (two phase), the steam entering the second stage is also two-phase. This is difficult to adequately depict in GETEM, where approximations are used for the steam properties, hence the estimates using two separate turbines. The method used to determine the turbine performance for a flash plant is presented using the state points shown in Figure A-29 below.

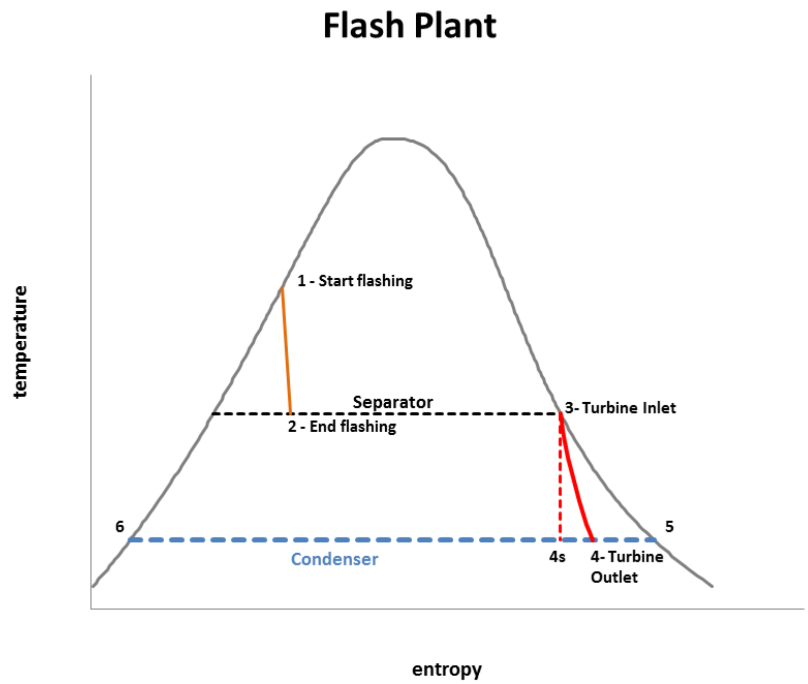


Figure A-29. Flash plant process state-points.

In depicting the turbine performance, point **3** in this figure represents the turbine inlet conditions. From this point, the steam is expanded to the exhaust pressure, represented here by the isothermal condenser. Ideally, the expansion would be isentropic with the steam exhausting the turbine at point **4s**. The ideal power produced by the turbine would be

$$\mathrm{power}_{\mathrm{turbine}_{\mathrm{ideal}}} = \dot{\mathrm{m}}_{\mathrm{steam}}(\mathrm{h}_3 - \mathrm{h}_{4\mathrm{s}})$$

Turbines are not 100% efficient, and because the expansion occurs within the two-phase region, there is additional efficiency loss. The actual turbine exhaust occurs at point **4**, and the actual power generated would be:

$$\mathrm{power}_{\mathrm{turbine}} = \dot{\mathrm{m}}_{\mathrm{steam}}(\mathrm{h}_3 - \mathrm{h}_4)$$

Using the approach given by DiPippo (2012), the enthalpy of the steam exhausting the turbine at point **4** can be determined as:

$$h_4 = \frac{h_3 - A\left[1 - \frac{h_6}{(h_5 - h_6)}\right]}{\left[1 + \frac{A}{(h_5 - h_6)}\right]}$$

where A is

$$A = \frac{\eta_{turbine}(h_3 - h_{4s})}{2}$$

h_6 is the saturation enthalpy of liquid water at the exhaust pressure

h_5 is the saturation enthalpy of water vapor at the exhaust pressure

h_3 is the turbine inlet enthalpy

h_{4s} is the enthalpy with a constant entropy expansion to the exhaust pressure

$\eta_{turbine}$ is the turbine efficiency (dry expansion) – GETEM default value is 80%.

As indicated, the turbine power is:

$$\text{power}_{turbine} = \dot{m}_{steam}(h_3 - h_4)$$

The steam flow rate used for the higher-pressure turbine in a dual-flash plant, or the turbine in a single-flash plant, is the amount of steam generated during the flashing process less the portion of this higher-pressure steam used to operate the steam ejectors in the non-condensable gas removal system.

$$\dot{m}_{steam} = \dot{m}_{steam_{1st\ flash}} - \sum \text{Steam flow}_{ncg\ stage}$$

With the dual-flash plants, the steam flow to the low-pressure turbine is equivalent to the amount of steam generated in the second or low-pressure flash.

The turbine power is determined for each turbine in a dual-flash system using the approach described. The total turbine output is the sum of the high- and low-pressure turbine outputs.

Heat Rejection

The amount of heat that is rejected is the sum of the heat duty of the main steam condenser and the heat duty of the condensers for each stage of the non-condensable gas removal system.

The heat duty (*Q*) for the main condenser is based on the enthalpy of the combined steam flow exiting the turbines, the total steam flow, and the saturated enthalpy of liquid water at the condensing temperature.

$$Q_{condenser} = [(m_{stm}h_{turbine\ exhaust})_{HP} + (m_{stm}h_{turbine\ exhaust})_{LP}] - \left[h_{f\ @Tcondenser}\left(\dot{m}_{stm_{HP}} + \dot{m}_{stm_{LP}}\right)\right]$$

In the non-condensable gas removal system, the heat load for each stage's condenser is estimated as:

$$Q_{staage_{ncg\ removal}} = \left[\dot{m}_{water\ vapor_{in}} + \dot{m}_{stm_{ejector}} - \dot{m}_{water\ vapor_{out}}\right](h_g - h_f)_{at\ T\ condenser}$$

The total heat rejected is:

$$Q_{cooling\ tower} = Q_{plant\ condenser} + \sum Q_{ncg\ removal_{stage}}$$

Water loss

The water loss for the evaporative heat rejection system used with flash plants is the sum of the following:

$$heat\ rejection\ loss = evaporation + drift + blowdown + losses\ ncg\ removal$$

Evaporative losses in the cooling tower are determined as a function of the wet bulb temperature specified, the amount of heat rejected, and the specified temperature rise of the cooling water in the condenser. The following relationship was developed using a combination of specifications for power plant cooling towers and model results:

$$evaporation = \left[a\left({T_{wb}}^3\right) + b\left({T_{wb}}^2\right) + c(T_{wb}) + d\right] \times Q_{cooling\ tower}$$
$$a = -0.0001769 \times \ln(\Delta T) + 0.0011083$$
$$b = 0.0657628 \times \ln(\Delta T) - 0.4091309$$
$$c = -6.7041142 \times \ln(\Delta T) + 44.3438937$$
$$d = -0.0325112(\Delta T^2) + 6.831236(\Delta T) - 64.6250943$$

$Q_{cooling\ tower}$ is the heat rejected (btu/hr)

T_{wb} is the specified wet bulb temperature (°F)

ΔT is the cooling water temperature rise (°F).

This relationship provides a representative depiction of the evaporation loss, which will vary from facility to facility, as well as throughout the year. While it is used to estimate the loss for flash plants, it can be used to estimate losses from any evaporative cooling tower. Table A-7 summarizes limited information on the losses from different facilities. With the exception of the one dry-steam plant, the above correlation provides estimates that are within 10% of the specified evaporative loss.

Table A-7. Evaporative loss from different geothermal facilities.

Conversion System	Facility Evaporative Loss (% of Circulating Water Flow)	GETEM Estimated Evaporative Loss	Information Source
Dry Steam	1.41%	1.39%	DiPippo ((2012)
Dry Steam	3.76%	3.28%	Geyser operator
Flash Steam	2.4%	2.55%	Operator (Imperial Valley)
Binary (Water Cooled)	1.17%	1.13%	Operator

The amount of water loss in the cooling tower due to drift is commonly estimated as some fraction of the circulating cooling water flow. Values for this fraction are small and vary as a function of the cooling tower design. Some designs have stated losses as low as 0.01%. Other sources suggest levels could be 0.2% of the cooling water flow. The EERE Federal Energy Management Program has a brochure on cooling towers that describes the different losses (EERE 2013). This brochure states these losses are small, and includes them in the determination of blowdown. In GETEM, the drift losses are estimated as 0.1% of the cooling water flow.

$$drift = 0.001 \times cooling\ water\ flow\ = 0.001\left[\frac{Q_{cooling\ tower}}{C_P \Delta T}\right],$$

with the assumption that the water has a specific heat (C_P) of 1 btu/lb-°F

Water loss for cooling water blowdown is estimated based on cycling the cooling water five times in the tower. This value is based information available for a steam plant. Note the binary plant had a lower number of cycles in the cooling tower (two to three times), but did not use the same quality of water for makeup.

$$blowdown = \frac{evaporation\ loss}{(5-1)} - Drift$$

The losses associated with the non-condensable gas removal are those determined in the vent stream leaving the 3rd stage condenser. Typically these losses are small unless the NCG concentrations specified are quite high.

$$water\ loss\ ncg\ removal_{moles} = ncg_{moles} \times \frac{(P_{total} - P_{water})}{P_{water}}$$

P_{total} is assumed to be 1 atm

ncg's are assumed to be CO_2

It is assumed that the total water loss from the flash plant heat rejection system is made up by the steam condensate. This assumption is inherent to both hydrothermal and EGS resources. With EGS, an alternative source of water is used to replace the steam condensate used for heat rejection makeup, so that the injected flow is equal to the produced flow plus any subsurface loss.

Parasitic Power Requirements

The power requirements for operating the plant are primarily associated with operation of the heat rejection system. The power for the vacuum pump used in the third stage of the of the non-condensable gas removal system was defined previously. In addition, there is power required for the fan, cooling water pump, and condensate pumps.

The cooling tower fan power is determined using a correlation developed from the results of modeling a cooling tower (and comparing those results to tower specifications from operating plants). This relationship is used to estimate the fan power per million btu/hr of heat rejected:

$$power_{fan\ per\ MMbtu/hr} = [-2.0814 \times \ln(\Delta T_{cw}) + 10.6013] \times e^{[-0.0188(\Delta T_{cw}{}^{0.0232})T_{wet\ bulb}]}$$

$$Q_{tower-basis} = \left(Q_{plant\ condenser} + \sum Q_{ncg\ removal}{}_{stage}\right)$$

$$power_{fan} = power_{fan\ per\ MMbtu/hr} \times (Q_{tower-basis}) \times 10^{-6}$$

For each condenser, the amount of cooling water required is based upon the assumption that the cooling temperature rise is the same in each of the condensers. (GETEM default value is a 20°F increase.)

$$\dot{m}_{cw} = \frac{Q_{tower}}{C_p(\Delta T_{cw})}$$

The power for the cooling water pump is based upon whether the specified condenser is a direct contact or surface condenser. (The default is a surface condenser.) Regardless of the type of condenser, a base head requirement is defined (default is 65 ft) to which a head requirement associated with each condenser type is added. For a surface condenser, it is assumed that the frictional pressure drop through the condenser is 10 psid. For the direct contact condenser, it is assumed that the cooling water must be pumped to bring the condenser pressure back to 1 atmosphere. The total pump head is:

$$head_{cw\ pump} = head_{base\ requirement} + \frac{\Delta P_{condenser\ type}}{\rho_{water}}$$

The cooling water pumping power for the main condenser is:

$$power_{cw\ pump-plant\ condenser} = \frac{head_{cw\ pump}(\dot{m}_{cw-condenser})}{\eta_{pump}}$$

The cooling water pump work is similarly calculated for the cooling water flow to each of the stage condensers in the non-condensable gas removal system. It is inherent to these calculations that these stage condensers are surface condensers (with a 10 psid cooling water pressure drop). The total cooling water pumping power is:

$$power_{cw-pump} = power_{cw\ pump-plant\ condenser} + \sum power_{cw\ pump-ncg\ removal}{}_{stage}$$

Pumping power is required for the steam condensate. For the main steam condenser, that power is based on a total pumping head that is the base head requirement plus the pump head needed to bring the condensate to 1 atmosphere. The base head requirement is included because it is assumed that this condensate will be circulated through the cooling tower.

$$\mathrm{head}_{\mathrm{condensate\ pump}_{\mathrm{main\ condenser}}} = \mathrm{head}_{\mathrm{base\ requirement}} + \frac{(\mathrm{P}_{\mathrm{atm}} - \mathrm{P}_{\mathrm{condenser}})}{\rho_{\mathrm{condensate}}}$$

For the stage condensers in the non-condensable gas removal system, the head requirement is that needed to bring the condensate to 1 atm.

$$\mathrm{head}_{\mathrm{condensate\ pump}_{\mathrm{ncg\ stage\ condenser}}} = \frac{(\mathrm{P}_{\mathrm{atm}} - \mathrm{P}_{\mathrm{condenser}})}{\rho_{\mathrm{condensate}}}$$

A lower head is used for these condensers because there is an inherent assumption that a portion of the steam condensate will be injected, and that the condensate from these condensers will be part of the fluid injected.

The condensate pumping power for each condenser is:

$$\mathrm{power}_{\mathrm{condensate\ pump}_{\mathrm{condenser}}} = \dot{\mathrm{m}}_{\mathrm{condensate}_{\mathrm{condenser}}}\left(\mathrm{head}_{\mathrm{condensate\ pump}_{\mathrm{condenser}}}\right)$$

With the total power being:

$$\mathrm{power}_{\mathrm{condensate\ pumping}} = \sum \mathrm{power}_{\mathrm{condensate\ pump}_{\mathrm{condenser}}}$$

The steam condensate not used as makeup for the heat rejection system is injected. The flow injected is:

$$\dot{\mathrm{m}}_{\mathrm{condensate}_{\mathrm{injected}}} = \sum \dot{\mathrm{m}}_{\mathrm{condensate}_{\mathrm{condenser}}} - \mathrm{heat\ rejection\ loss}$$

The power required is:

$$\mathrm{power}_{\mathrm{condensate\ injection}} = \frac{\left[\dot{\mathrm{m}}_{\mathrm{condensate}_{\mathrm{injected}}}(\mathrm{P}_{\mathrm{lowest\ flash\ pressure}} - \mathrm{P}_{\mathrm{atm}})\right]}{\eta_{\mathrm{pump}}(\rho_{\mathrm{condensate}})}$$

This is the amount of power needed to bring the condensate to the lowest flash-separator pressure (assumed pressure at suction of the injection pumps).

The total parasitic power is:

$$\sum \mathrm{parasitic\ power} = \mathrm{power}_{\mathrm{vacuum\ pump}} + \mathrm{power}_{\mathrm{fan}} + \mathrm{power}_{\mathrm{cw-pump}} + \mathrm{power}_{\mathrm{condensate\ pumping}} + \mathrm{power}_{\mathrm{condensate\ injection}}$$

Plant Size

The plant size is based on the net power needed for the plant in order to produce the specified sales. To do so, first the net brine effectiveness (be_{net}) for the plant is determined. That value is:

$$be_{net} = \frac{\left[\eta_{generator} \sum power_{turbine} - \sum parasitic\ power\right]}{m_{gf}{}_{basis}}$$

The default generator efficiency ($\eta_{generator}$) is 98%. The sum of the parasitic power is all the power needed to operate the plant, but does not include any geothermal pumping power. Again, the basis for the calculations is a geothermal flow of 1,000 lb/hr entering the plant.

The specific geothermal pumping power (power per unit mass) for a project is determined as described in Appendix A8. This value is used with the net brine effectiveness for the plant and the specified power sales to determine the total flow rate required.

$$\dot{m}_{gf_{required}} = \frac{power\ sales}{(be_{net} - specific\ geothermal\ pumping\ power)}$$

With the total geothermal flow rate determined, the plant size needed to provide the specified sales can be determined.

$$\text{plant size}_{\text{net}} = \text{be}_{\text{net}}\left(\dot{\text{m}}_{\text{gf}_{\text{required}}}\right)$$

With the geothermal flow determined, the individual parasitic loads in the plant can be determined.

Plant Cost

The approach used to determine the cost of a flash plant is analogous to that used in the ERPI report (EPRI 1996) on the next generation of geothermal power plants. The major plant component costs are estimated, and an installation multiplier is applied to those costs to establish the installed plant cost. The cost correlations used in GETEM are based on cost estimates made with Aspen Technology's Icarus Process Evaluator (IPE) software and the cost estimates from the EPRI study.

Cost estimates are made for the following major components in flash -steam plants:

- Turbine-generator
- Flash-separator vessels
- Cooling tower
- Condenser
- Pumps
- NCG removal system
- Hydrogen sulfide abatement system.

The size of these components and systems are based upon the component sizes determined when determining the base plant performance with a geothermal flow of 1,000 lb/hr ($m_{gf\,basis}$). Those sizes are scaled up linearly with the total flow required to produce the desired power sales.

Turbine-Generator Set

Though the turbine is determined as two separate turbines for dual-flash plants, the turbine-generator cost is determined based on the total gross output from the plant (in KW).

$$\text{power}_{\text{gross}} = \left[\eta_{\text{generator}} \times \sum \text{power}_{\text{turbines}}\right]\left(\frac{\dot{\text{m}}_{\text{gf}_{\text{required}}}}{\dot{\text{m}}_{\text{gf}_{\text{basis}}}}\right)$$

The turbine-generator cost is determined using the following cost correlation from IPE (in 2002 dollars).

$$\text{cost}_{\text{turbine-generator}} = 2830\left({\text{power}_{\text{gross}}}^{0.745}\right) + 3685\left({\text{power}_{\text{gross}}}^{0.617}\right)$$

The first term in this relationship is the turbine cost; the second the generator cost.

Cooling Tower

The estimated cost (in 2002 dollars) of the cooling tower is based on the amount of heat that is rejected (Q_{reject}) from the tower. This value is determined by multiplying the value for the amount of heat rejected (that was determined when establishing the plant performance by the ratio of the geothermal fluid flow rate required) to that used when determining performance (1,000 lb/hr).

$$\mathrm{Q_{reject}} = \mathrm{Q_{tower-basis}}\left(\frac{\dot{\mathrm{m}}_{\mathrm{gf}_{\mathrm{required}}}}{\dot{\mathrm{m}}_{\mathrm{gf}_{\mathrm{basis}}}}\right)$$
$$\mathrm{cost_{cooling\ tower}} = 7800\left(\mathrm{Q_{reject}}^{0.8}\right)$$

Condenser

The condenser cost is estimated (in 2002 dollars) for either a surface condenser or a direct contact condenser. The surface condenser size is estimated based on the heat rejected in the main steam condenser and the defaults used for the cooling water temperature rise (20°F), the minimum approach temperature between the cooling water and the steam (7.5°F), and the overall heat transfer coefficient U (350 btu/hr-ft^2-°F). (GTO can adjust these defaults on the *DEFAUT Inputs* worksheet.) The heat load in the condenser is determined in a similar manner to the cooling tower heat load; the heat load found when establishing plant performance is multiplied by the ratio of the geothermal flow required to that used when determining performance.

$$\mathrm{area_{surface\ condenser}} = \frac{\mathrm{Q_{condenser}}}{\mathrm{U(LMTD)}}$$

The LMTD is the log mean temperature difference that is determined from the water temperature rise and the approach temperature (assuming no de-superheating or subcooling of the steam). The correlation used to estimate cost as a function of size was derived from IPE cost estimates of heat exchangers with stainless steel tubes.

$$\mathrm{cost_{surface\ condenser}} = 102(\mathrm{area_{surface\ condenser}}^{0.85})$$

If a direct contact condenser is used, its cost is estimated using the correlation below, which was developed from estimates in the 1996 EPRI study (EPRI 1996) after bringing the EPRI estimates to 2002 using the Bureau of Labor Statistics Producer Price Index (United States Department of Labor) for process equipment.

$$\mathrm{cost_{direct\ contact\ condenser}} = \mathrm{Q_{condenser}} \times \left[1.25\left(\mathrm{T_{gf}}\right) + 1480\right]$$

In this relationship, the geothermal temperature (T_{gf}) is in °C; it is the resource temperature less the temperature loss in the well (i.e., the temperature before flashing occurs in the well). The condenser heat load ($Q_{condenser}$) in this relationship is in millions of btu per hr.

Pump

The pump cost used is the sum of the cooling water pump cost and the condensate pump costs. The pumping power for both were estimated in determining the plant performance with the base geothermal flow (1,000 lb/hr). The actual power required for each is determined by multiplying the power determined in the performance calculations by the ratio of the required brine flow to that used in the performance calculations. The same cost correlation is used for each pump type.

$$\mathrm{cost_{cw\ pump}} = 2.35 * 1185\left(\mathrm{power_{cw\ pump}}^{0.767}\right)$$
$$\mathrm{cost_{condensate\ pump}} = 2.35 * 1185\left(\mathrm{power_{condensate\ pump}}^{0.767}\right)$$

This cost correlation is from IPE estimates of pump costs as a function of power, with power expressed as horsepower. The 2.35 multiplier used in both relationships is the added cost for a stainless steel pump.

$$\mathrm{cost_{pump}} = \mathrm{cost_{cw\ pump}} + \mathrm{cost_{condensate\ pump}}$$

This pump cost is in 2002 dollars.

Non-Condensable Gas Removal System

The cost of the non-condensable gas removal system is based on the type of removal system being used. (The default is a hybrid system.) Four component costs are determined: vacuum pump, condensers, condensate pumps, and steam ejectors. These components were sized for the geothermal flow rate used to determine the flash plant performance, with their final size varying directly with the ratio of the flow required to that used to determine performance.

Vacuum Pump

The vacuum pump cost for each stage having a vacuum pump is:

If vacuum pump power is less than 5,000 kW:

$$\text{cost}_{\text{vacuum pump}_{\text{stage}}} = 70000\left(\text{power}_{\text{vacuum pump}}{}^{0.34}\right)$$

else

$$\text{cost}_{\text{vacuum pump}_{\text{stage}}} = 7400\left(\text{power}_{\text{vacuum pump}}{}^{0.6}\right)$$

In these relationships, the vacuum pump power is in kW. The costs are based on IPE estimates in 2002 dollars and include the cost of the motor. The total vacuum pump cost is:

$$\text{cost}_{\text{vacuum pump}} = \sum \text{cost}_{\text{vacuum pump}_{\text{stage}}}$$

The default is to use a vacuum pump for only the third stage. Though this is not a default that can be revised, GTO can revise inputs to use all vacuum pumps or to use all steam ejectors.

Condenser

The stage condenser costs are based on the heat load for that stage, and the U and LMTD used to determine the plant steam condenser cost. The relationship for the cost of each condenser is based on IPE costs that are in 2002 dollars, and assumes the use of stainless steel tubes.

$$\text{cost}_{\text{condenser}_{\text{stage}}} = 322\left(\text{area}_{\text{condenser}}{}^{0.6}\right)$$

The total condenser cost is the sum of the costs determined for each stage:

$$\text{cost}_{\text{ncg condensers}} = \sum \text{cost}_{\text{condenser}_{\text{stage}}}$$

Condensate Pumps

The same relationship used to estimate the costs for the cooling water and main condenser steam condensate pumps is also used to estimate costs of the steam condensate pumps used to bring the condensate from the non-condensable removal system to 1 atm. These pumps are used for the first and second stages, but not the third, during which condensation occurs at 1 atmosphere.

$$\text{cost}_{\text{condensate pump}_{\text{stage}}} = 2.35 * 1185\left(\text{power}_{\text{condensate pump}}{}^{0.767}\right)$$

Again, the pumps are stainless steel and the power used is the pump’s horsepower. The total cost for the condensate pumps is:

$$\text{cost}_{\text{ncg condensate pumps}} = \sum \text{cost}_{\text{condensate pump}_{\text{stage}}}$$

Steam Ejectors

The steam ejector costs are also based on correlations developed from IPE estimates in 2002 dollars. The costs are based on the ratio of the supply steam pressure to the suction pressure and the non-condensable gas flow (lb/hr). A relationship is developed for each of the three stages.

First stage:

$$\mathrm{cost}_{\mathrm{ejector-stage\ 1}} = \dot{\mathrm{m}}_{\mathrm{ncg}}\left[76\left(\frac{\mathrm{P}_{\mathrm{supply\ steam}}}{\mathrm{P}_{\mathrm{suction-stage\ 1}}}\right)^{-0.45}\right]$$

Second stage:

$$\mathrm{cost}_{\mathrm{ejector-stage\ 2}} = \dot{\mathrm{m}}_{\mathrm{ncg}}\left[43\left(\frac{\mathrm{P}_{\mathrm{supply\ steam}}}{\mathrm{P}_{\mathrm{suction-stage\ 2}}}\right)^{-0.63}\right]$$

Third stage (not default):

$$\mathrm{cost}_{\mathrm{ejector-stage\ 3}} = \dot{\mathrm{m}}_{\mathrm{ncg}}\left[43\left(\frac{\mathrm{P}_{\mathrm{supply\ steam}}}{\mathrm{P}_{\mathrm{suction-stage\ 3}}}\right)^{-0.63}\right]$$

The total cost for the steam ejectors is:

$$\mathrm{cost}_{\mathrm{ncg\ ejectors}} = \sum \mathrm{cost}_{\mathrm{ejector}_{\mathrm{stage}}}$$

The total cost for the non-condensable gas removal system is:

$$\mathrm{cost}_{\mathrm{ncg\ removal}} = \mathrm{cost}_{\mathrm{vacuum\ pump}} + \mathrm{cost}_{\mathrm{ncg\ condensers}} + \mathrm{cost}_{\mathrm{ncg\ condensate\ pumps}} + Cost_{ncg\ ejectors}$$

Hydrogen Sulfide Abatement

Minimal information exists upon which to base the cost for abatement of hydrogen sulfide. The estimate made is based on cost information in the 1995 ERPI Next Generation Geothermal Power Plant study after bringing those estimates to 2002 using the Bureau of Labor Statistics Producer Price Index for process equipment.

$$\mathrm{cost}_{\mathrm{H_2S\ Abatement}} = 115000\left(\dot{\mathrm{m}}_{\mathrm{H_2S}}{}^{0.58}\right)$$

In this relationship, the H_2S flow (m_{H2S}) is the flow in lb/hr

Flash-Separator Vessels

The flash-separator vessel cost is based on the steam flow and a specified maximum entrained liquid water drop size. The flash–separator pressure and steam mass flow from that vessel determines the volumetric flow rate. For the specified droplet size (the default is a 200-micron diameter), the following relationship is used to determine its settling velocity. (This was derived from a curve fit of calculated velocities for a range of conditions.)

$$\mathrm{V}_{\mathrm{settling}} = 0.009414\left(\mathrm{D}_{\mathrm{drop}}{}^{2}\right)[\ln(\mathrm{P}_{\mathrm{flash}})] + 0.1096\left(\mathrm{D}_{\mathrm{drop}}{}^{2}\right)$$

where

$V_{settling}$ is settling velocity in ft/s

D_{drop} is drop diameter in inches

P_{flash} is flash pressure in psia.

The area of the flash vessel is

$$\mathrm{A} = \frac{\left(\dot{\mathrm{m}}_{\mathrm{steam-flash}}/\rho_{\mathrm{steam-flash}}\right)}{\mathrm{V}_{\mathrm{settling}}}$$

An arbitrary limit of 300 ft^2 is placed on the separator cross-sectional area—if larger, two vessels are required. It is assumed that the vessel height is three times its diameter. The height and diameter are used to determine the volume of the vessel in gallons. This capacity is used to estimate cost (in 2002 dollars).

If P_{flash} <75 psia

$$\text{Cost}_{\text{flash-separator}} = 166.5\left(\text{Capacity}_{\text{vessel-gal}}{}^{0.625}\right)$$

Else

$$\text{Cost}_{\text{flash-separator}} = 110\left(\text{Capacity}_{\text{vessel-gal}}{}^{0.68}\right)$$

These costs were derived from IPE estimates of pressure vessels. These correlations are used for both the high- and low-pressure flash-separator vessels. If multiple vessels are required at either flash level, the size of an individual vessel is determined and a cost estimated for that size. The cost of the flash-separator vessels at that flash level is this cost multiplied by the number of vessels needed.

Total Flash Plant Cost

The cost estimates for the major plant components are in 2002 dollars. They are adjusted to the year for which the GETEM estimate is being made using the PPIs from the Bureau of Labor Statistics. Once applied, a total cost is found for the major equipment items. Using an approach that is analogous to that in the EPRI report (EPRI 1996), a multiplier is applied to these costs to get a total installed cost at the start of operation.

$$\text{installed plant cost} = \text{installation multiplier} \times \sum \text{PPI}\left(\text{cost}_{\text{major equipment}}\right)$$

The installation multiplier is determined as:

$$\text{installation multiplier} = \text{multiplier}_{\text{direct construction}}(1 + \text{indirect cost multiplier})$$

Both the direct construction multiplier and the indirect cost multiplier are specified inputs that can be revised. The default value for the direct construction multiplier is determined using an approach based on IPE estimates for flash steam power plants. The multiplier consists of:

- Other materials
- Labor
- Other construction (on-site construction management/supervision, construction expendables, and rentals)
- Tax
- Freight

The other materials include the cost of steel, piping, concrete, electrical equipment, instrumentation, insulation, paint, buildings, and similar things needed during plant construction. The value used is derived from the IPE estimates as a function of the resource temperature (°C) less temperature loss in the well bore. The multiplier for the total material costs varies inversely with this temperature; the value used is:

$$\text{total materials multiplier}_{2002} = 8.65\left(\text{T}_{\text{gf}}{}^{-0.297}\right)$$

This value, multiplied by the major component costs, is the total materials costs for the project, including the "other materials." The contributors to the direct construction multiplier are based on the major component costs in 2002 dollars. Though the magnitude of all contributions to the construction multiplier are adjusted using PPIs, this multiplier is applied to equipment costs that have unique PPIs as well. To account for the effect that the equipment PPIs would otherwise have on the contribution of these other costs, an effective PPI is determined for the major component costs. This value is then used to adjust the effect of the PPIs applied to each of the contributors to direct the construction cost multiplier. This adjustment is determined as:

$$\text{major component cost adjustment, or MCCA} = \frac{\sum\left[\text{component cost}_{2002}\left(\text{PPI}_{\text{component}}\right)\right]}{\sum \text{component cost}_{2002}}$$

The PPI for process equipment is applied to the "other materials" contribution and corrected with the above adjustment to remove the effects of changes to the major equipment costs. The resulting total materials multiplier is:

$$\text{total materials multiplier} = 1 + (\text{total materials multiplier}_{2002} - 1)\left[\frac{\text{PPI}_{\text{process equipment}}}{\text{MCCA}}\right]$$

This multiplier is used to determine the total material costs for the plant construction for the year of the estimate. This includes major component costs and the "other" materials.

$$\text{total material costs} = \text{total materials multiplier} \times \sum \text{component cost}_{2002}\left(\text{PPI}_{\text{component}}\right)$$

The labor cost multiplier component is also derived from IPE estimates as a function of the resource temperature (°C) less well bore losses:

$$\text{labor multiplier}_{2002} = 61.843\left(\text{T}_{\text{gf}}{}^{-0.923}\right)$$

In the year of interest, the multiplier is:

$$\text{labor multiplier} = \text{labor multiplier}_{2002}\left(\frac{\text{PPI}_{\text{labor}}}{\text{MCCA}}\right)$$

The contribution of construction supervision, expendables, and rentals to the installation multiplier is based on the IPE estimates as well, and is also determined as a function of the resource temperature (°C) less well bore losses.

$$\text{other construction multiplier}_{2002} = 16.177\left(\text{T}_{\text{gf}}{}^{-0.827}\right)$$

In the year of interest, the multiplier is:

$$\text{other construction multiplier} = \text{other construction multiplier}_{2002}\left(\frac{\text{PPI}_{\text{process equipment}}}{\text{MCCA}}\right)$$

The taxes and freight rates are default inputs that cannot be revised. They are applied to the material costs and the other construction costs (not to labor).

The direct construction multiplier is:

$$\begin{aligned} multiplier_{direct\ construction} = {} & labor\ multiplier + total\ materials\ multiplier(1 + tax + freight) \\ & + other\ construction\ multiplier(1 + tax + freight) \end{aligned}$$

The indirect costs for the plant construction include engineering, home office, startup, and other activities not directly associated the plant construction. They are determined as a specified (input) fraction of the direct construction costs. (Note that engineering is assumed to be 50% of these indirect costs; in the project schedule, half of these engineering costs are incurred before obtaining the PPA.) The total installation multiplier is:

$$\text{installation multiplier} = \text{multiplier}_{\text{direct construction}}(1 + \text{indirect cost multiplier})$$

The total installed plant cost is:

$$\text{installed plant cost} = \text{installation multiplier} \times \sum \text{PPI}\left(\text{cost}_{\text{major equipment}}\right)$$

The following shows values for an example scenario:

- Major component cost (in year of interest), or $\sum PPI(cost_{major\ equipment})$: $10,000,000
- Labor multiplier: 0.4
- Other construction multiplier: 0.2
- Total materials multiplier: 1.8
- Taxes: 0.06
- Freight: 0.05

- Indirect costs: 12%
- $Multiplier_{direct\ construction}$ = 0.4 + 1.8*(1+0.06+0.05)+0.2*(1+0.06+0.05) = 2.62
- Installation multiplier = 2.62*(1+0.12) = 2.934
- Installed plant cost = 2.934 * $10,000,000 = $29,340,000.

The installed plant cost calculated using both specified and default inputs is reported in $/kW of net plant output. Note this is not per kW of sales, but the sales plus the geothermal pumping required. The cost that is calculated can be revised.

Air-Cooled Binary Plants

As indicated, the use of the binary working fluid adds an additional degree of freedom in designing an air-cooled binary plant. Determining the performance and cost of a binary plant using an approach similar to that used for the flash plant would require fluid property add-ins to Excel for all potential working fluids, as well as the properties of air. Even with the properties, finding an optimal design for the binary plant would be a daunting task. In lieu of this approach, results of other modeling activities were used to establish relationships between the cost and performance of these binary plants. GETEM uses these relationships to determine the cost of a binary plant based on its performance.

The first law efficiency, or thermal efficiency, is frequently used as a performance metric for binary plants.

$$\eta_{\text{thermal}} = \frac{\text{net power}}{\text{heat extracted from geofluid}}$$

With this efficiency, the denominator is a function of the design of the plant. As such, it is difficult to correlate this efficiency with the geothermal flow rate required to produce the desired level of power. In order to relate plant performance to the geothermal flow rate, GETEM uses both the second law efficiency and brine effectiveness as binary plant performance metrics. Brine effectiveness is the numerator in the second law efficiency as shown here:

$$\eta_{\text{II}} = \frac{\text{brine effectiveness}}{\text{available energy}}$$

Once the resource temperature and an ambient temperature are defined, the available energy is fixed, and the brine effectiveness and second law efficiency are effectively interchangeable.

Figure A-30 below shows the relationship between the first and second law efficiencies and the amount of power produced from a 150°C resource, with a fixed flow rate and an ambient temperature of 10°C. This figure illustrates the difficulty in relating the thermal efficiency to power and/or flow rate. Some of the plants with the higher thermal efficiencies have relatively low levels of power output; this is because these cycles extract less heat from a given geothermal flow rate. In contrast, the power output varies directly with second law efficiency (flow rate varies inversely).

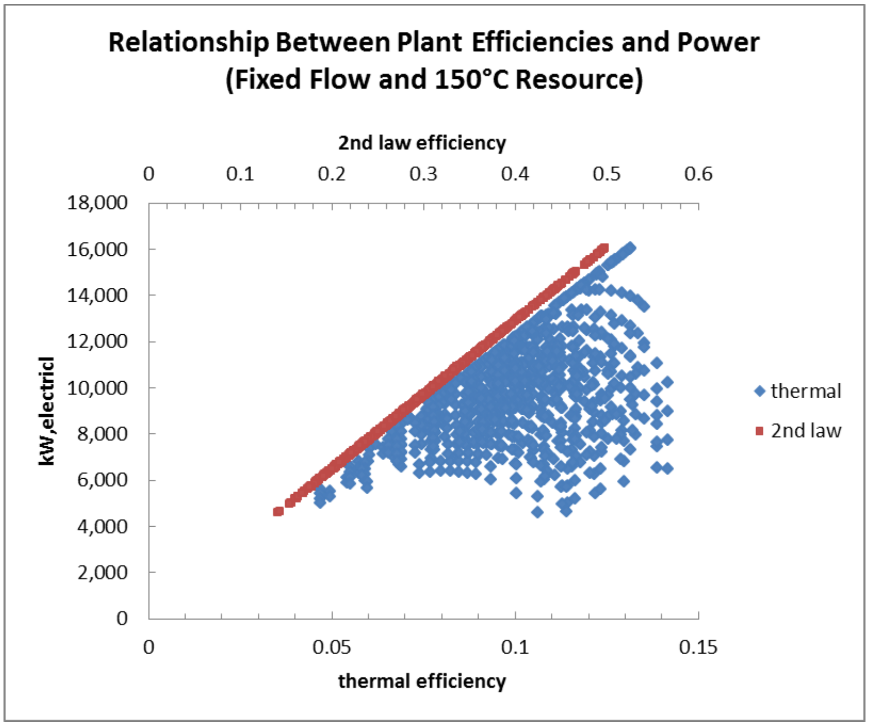


Figure A-30. The relationship between first and second law efficiencies and power produced for a 150°C resource.

In addition to the direct correlation between the second law efficiency and power, this metric can be more readily correlated to plant cost. This is illustrated below in Figure A-31, in which estimated equipment costs for a 10 MW plant are shown as a function of both efficiencies.

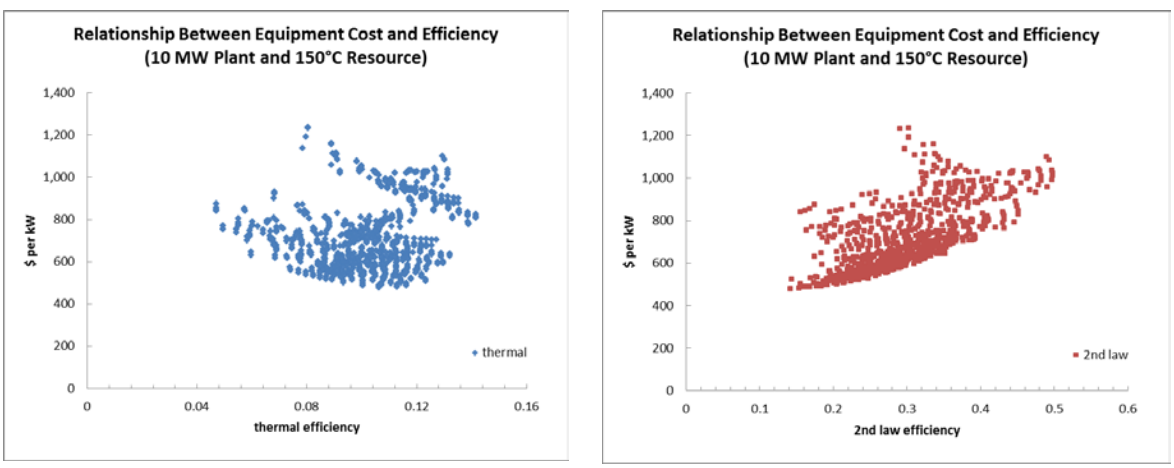


Figure A-31. Estimated equipment costs for a 10 MW plant as a function of thermal efficiency (left) and second law efficiency (right).

Though there is considerable scatter in cost with both efficiencies, the costs do trend directly with the second law efficiency. This trend is the basis for GETEM's determination of binary plant costs.

Figure A-31 shows the results of modeling with a 150°C resource temperature that considered multiple working fluids, varying minimum approach temperatures in both the geothermal heat exchanger and the air-cooled condenser, and varying turbine inlet conditions. Modeling was initially done at a fixed geothermal flow rate (5,000 gpm), and those results were used to scale equipment size to a 10 MW net plant output. Both resource and ambient temperatures were held constant, and the condensing temperature varied, given the maximum net output for the specific conditions being evaluated. (Net plant output is the generator output less the working fluid pumping power and fan power required.) Equipment costs were estimated for all modeled scenarios (for 10 MW plants) using correlations developed from Aspen's IPE estimates.

Resource temperatures from 75°C to 200°C were modeled at increments of 25°C. The working fluids considered were propane, isobutane, normal butane, isopentane, R134a, and R245fa. All plants were modeled having a single vaporizer (dual boiling cycles were not evaluated), with a maximum working fluid turbine inlet pressure of 1,200 psia. Supercritical cycles were modeled; they have both higher levels of performance and higher costs.

Below in Figure A-22 are the equipment cost estimates for the 100°C and 200°C resources as functions of the second law efficiency for the 10 MW net plant. Similar estimates were made for the 75°, 125°, and 175°C resources as well.

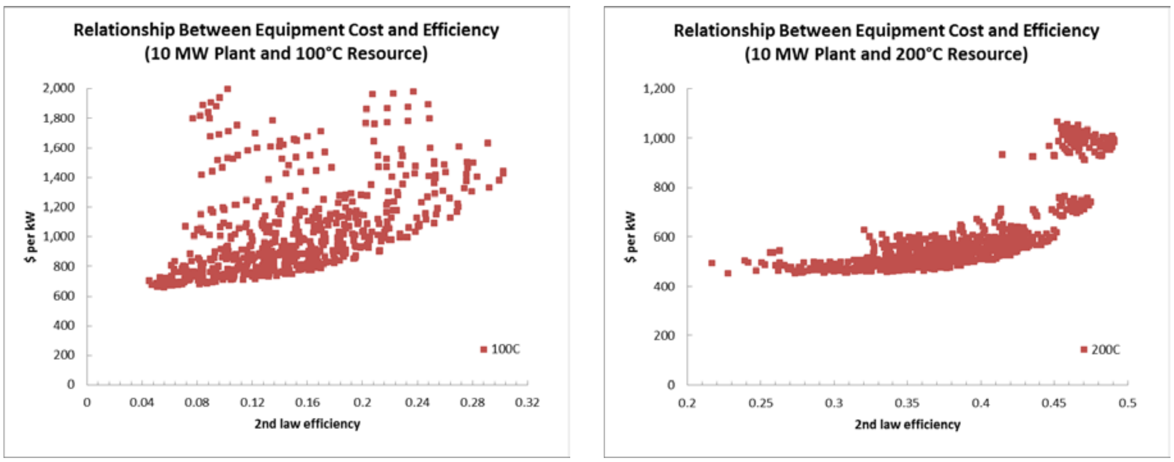


Figure A-32. Equipment cost estimates for a 100°C (left) and a 200°C resource (right).

For each resource temperature, the cost estimates were sorted and only those that were approaching the minimum cost at a given level of performance were selected. That down select is shown below in Figure A-33 for the 150°C resource (again, for a 10 MW plant).

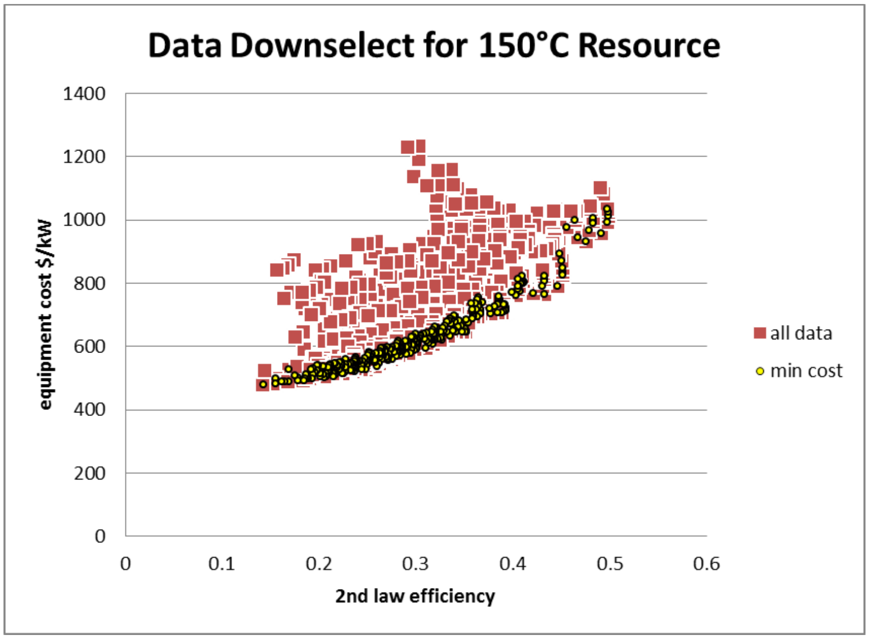


Figure A-33. Cost data down select for a 150°C resource.

This screening of the cost data was done for each of the six resource temperatures evaluated. This minimum cost data set was then used to develop cost correlations for the major equipment components in a 10 MW plant as functions of both temperature and performance (second law efficiency).

Binary Plant Component Costs

The installed binary plant cost is determined similarly to the flash steam plant in that:

$$\text{installed plant cost} = \text{installation multiplier} \times \sum \text{PPI}\left(\text{cost}_{\text{major equipment}}\right)$$

It differs from the flash plant in how the major component costs are determined. For the flash plant, a method was used to estimate the size of the individual components for a specified plant size; alternately, for binary plants, the component costs are estimated for a 10 MW net plant. Those estimates are based on the temperature of the geothermal resource and the plant performance (second law efficiency). For the binary plants, costs are estimated for four major components or equipment items.

- Turbine generator set
- Air-cooled condenser
- Geothermal heat exchangers
- Working fluid pump.

The correlations that are developed for each component are in 2002 dollars, and are based on component costs estimated using IPE. Once sized for the 10 MW net plant, component costs are scaled to the required size for the specified sales. PPIs are then applied to bring these component costs to the year of interest.

Turbine-Generator

The turbine-generator cost is based on an estimated gross output (generator output). The parasitic load is estimated using the following relationship:

$$\text{parasitic power} = \text{power}_{\text{net output}}\left[\text{CT1} \times \text{e}^{\text{CT2}(\eta_{\text{II}})}\right]$$

The net power ($power_{net\ output}$) is the base plant output of 10MW; $CT1$ and $CT2$ are both functions of the plant inlet temperature (in °C).

$$\text{CT1} = -5.321 \times 10^{-8}\left(\text{T}_{\text{gf}}{}^{3}\right) + 4.24483 \times 10^{-5}\left(\text{T}_{\text{gf}}{}^{2}\right) - 0.00977366\left(\text{T}_{\text{gf}}\right) + 0.796648$$
$$\text{CT2} = 5.52551 \times 10^{-6}\left(\text{T}_{\text{gf}}{}^{3}\right) - 0.00296255\left(\text{T}_{\text{gf}}{}^{2}\right) + 0.49768132\left(\text{T}_{\text{gf}}\right) - 24.628893$$

These expressions used to establish the parasitic power were developed from the modeled scenarios that produced minimum cost vs. performance at each of the resource temperatures.

The estimated gross generator output is:

$$\text{gross output} = \text{power}_{\text{net output}} + \text{parasitic power}$$

This output was compared to a limit of 15,000 hp (11.186 MW) imposed on binary turbine size. If the gross output exceeds this value, multiple turbines are needed.

The turbine-generator cost is determined as

$$\text{cost}_{\text{turbine}} = \frac{7400(\text{gross output}^{0.6})}{\text{power}_{\text{net output}}} \times \text{size ratio}$$
$$\text{size ratio} = 1 \text{ if gross output} < 11{,}186 \text{ kW, else} = \frac{\text{gross ouput}}{11{,}186 \text{ kW}}$$

The gross output used is in kW. If the gross output exceeds the maximum size limit imposed (11,187 kW), then this maximum size is used as the output in this cost correlation. The cost that is determined in \$/kW is for a 10 MW_{net} plant. The estimated generator differs in that it is based on the estimated gross output from the 10 MW_{net} plant—no constraint is placed on the generator output.

$$\text{cost}_{\text{generator}} = \frac{1800(\text{gross output}^{0.67})}{\text{power}_{\text{net output}}}$$

This cost is in \$/kW of net plant output. The total turbine-generator set cost is:

$$\text{cost}_{\text{turbine-generator set 2002}} = \text{cost}_{\text{turbine}} + \text{cost}_{\text{generator}}$$

This is the cost for a 10 MW plant in 2002 dollars. The cost in the year of interest of a 10 MW plant is:

$$\text{cost}_{\text{10 MW t-g set}} = \text{cost}_{\text{turbine-generator set 2002}}\left(\text{PPI}_{\text{turbine-generator}}\right)$$

The turbine-generator cost (\$/kW_{net}) for the plant necessary to provide the specified power sales is:

$$\text{cost}_{\text{t-g set}} = \left(\frac{\text{size necessary}/_{\text{\# modular units}}}{10 \text{ MW}}\right)^{\text{TSF}} \times \left(\frac{10{,}000 \times \text{cost}_{\text{10 MW t-g set}}}{\text{size necessary}/_{\text{\# modular units}}}\right)$$

Size necessary is the net plant output required for the specified power sales

 # modular units is the number of modules if the plant is modular

TSF is the turbine cost scaling factor with size

TSF is a function of the resource temperature and the size of the modular unit turbine size

- ($^{size\ necessary}/_{\#\ modular\ units}$). If the modular unit turbine size is 10 MW or greater, this scaling factor is 1.

- If <1, *TSF* is a function of the resource temperature. It is based on modeled results using the IPE software to estimate plant costs.

$$\mathrm{TSF} = -2.0218 \times 10^{-6}\left(\mathrm{T_{gf}}^2\right) + 0.000358909\left(\mathrm{T_{gf}}\right) + 0.6642$$

This cost ($cost_{t\text{-}g\ set}$) is the cost of the turbine generator for the plant in $/kW for the year of interest. It is adjusted to provide the specified sales and to reflect the use of modular units.

Air-Cooled Condenser

The air-cooled condenser costs are also first determined for a 10 MW_{net} plant. The cost for this air-cooled condenser is:

$$\mathrm{cost_{AC\ condenser-2002}} = \mathrm{AC1}(\eta_{\mathrm{II}}{}^{\mathrm{AC2}}) + \mathrm{AC0}$$

Where $AC1$, $AC2$, and $AC0$ are functions of the geothermal fluid temperature (°C).

$$AC0 = 11568490\left(T_{gf}{}^{-2.35092}\right) + 47$$

$$AC1 = e^{\left[5.65748\times10^{-6}\left(T_{gf}{}^3\right)-0.001200635\left(T_{gf}{}^2\right)+0.005950211\left(T_{gf}\right)+15.52712\right]}$$

$$AC2 = e^{\left[-2.54939\times10^{-7}\left(T_{gf}{}^3\right)+0.000277465\left(T_{gf}{}^2\right)-0.05107826\left(T_{gf}\right)+3.584261\right]}$$

This cost for the air-cooled condenser is again for a 10 MW plant and is in $/kW (2002 dollars). To get this base 10 MW plant cost in the year of interest, a PPI is applied.

$$cost_{10\ MW\ AC\ condenser} = cost_{AC\ condenser-2002}\left(PPI_{heat\ exchangers}\right)$$

A scaling factor is not applied to the cost of these condensers. Cost estimate modeling with IPE indicated that after ~three condenser bays were used, there was little scaling of cost with size. For plants of interest (>5 MW) more than three condenser bays would be required. The condenser cost is equivalent to the base 10 MW plant cost, in $/kW.

$$cost_{AC\ condenser} = cost_{10\ MW\ AC\ condenser}$$

Geothermal Heat Exchanger

The geothermal heat exchanger costs are similarly determined. The cost in $/kW for the 10 MW base plant is:

$$\mathrm{cost_{GF\ exchangers-2002}} = \mathrm{GHX1} \times \mathrm{e}^{[\mathrm{GHX2}(\eta_{\mathrm{II}})]}$$

The values GHX1 and GHX2 are functions of the geothermal fluid temperature (°C).

$$\mathrm{GHX1} = 2163827753\left(\mathrm{T_{gf}}^{-3.8105414}\right) + 5.95$$

$$\mathrm{GHX2} = 4.24462 \times 10^{-6}\left(\mathrm{T_{gf}}^3\right) - 0.002356472\left(\mathrm{T_{gf}}^2\right) + 0.4275955\left(\mathrm{T_{gf}}\right) - 22.09917$$

Again, this cost is in 2002 dollars. They are adjusted to the year of interest (the year for which the estimate is made).

$$\mathrm{cost_{10\ MW\ GF\ exhcnagers}} = \mathrm{cost_{GF\ exchangers-2002}}\left(\mathrm{PPI_{heat\ exchangers}}\right)$$

The geothermal heat exchanger costs do scale with size:

$$\mathrm{cost_{GF\ exhcnager}} = \left(\frac{\text{size necessary}/\text{\# modular units}}{10\ \mathrm{MW}}\right)^{\mathrm{GHXSF}} \times \left(\frac{10{,}000 \times \mathrm{cost_{10\ MW\ GF\ exhcnagers}}}{\text{size necessary}/\text{\# modular units}}\right)$$

The scaling factor for the geothermal heat exchangers (*GHXSF*) is a function of the resource temperature:

$$\mathrm{GHXSF} = 2.0145 \times 10^{-6}\left(\mathrm{T_{gf}}^2\right) - 0.000760473\left(\mathrm{T_{gf}}\right) + 1.01216$$

Working Fluid Pump

The relationship used for the base 10 MW plant working fluid pump cost is:

$$\text{cost}_{\text{WF pump}-2002} = \text{WFP1} \times e^{[\text{WFP2}(\eta_{\text{II}})]}$$

The values *WFP1* and *WFP2* are functions of the geothermal temperature (°C).

$$\text{WFP1} = 0.0006714\left({T_{gf}}^{2}\right) - 0.25379\left(T_{gf}\right) + 32.06071$$
$$\text{WFP2} = -0.0001977\left({T_{gf}}^{2}\right) + 0.0559291\left(T_{gf}\right) - 0.3329714$$

A PPI for pumps is applied to get the base plant pump cost in the year of interest.

$$\text{cost}_{\text{10 MW WF pump}} = \text{cost}_{\text{WF pump}-2002}\left(\text{PPI}_{\text{pump}}\right)$$

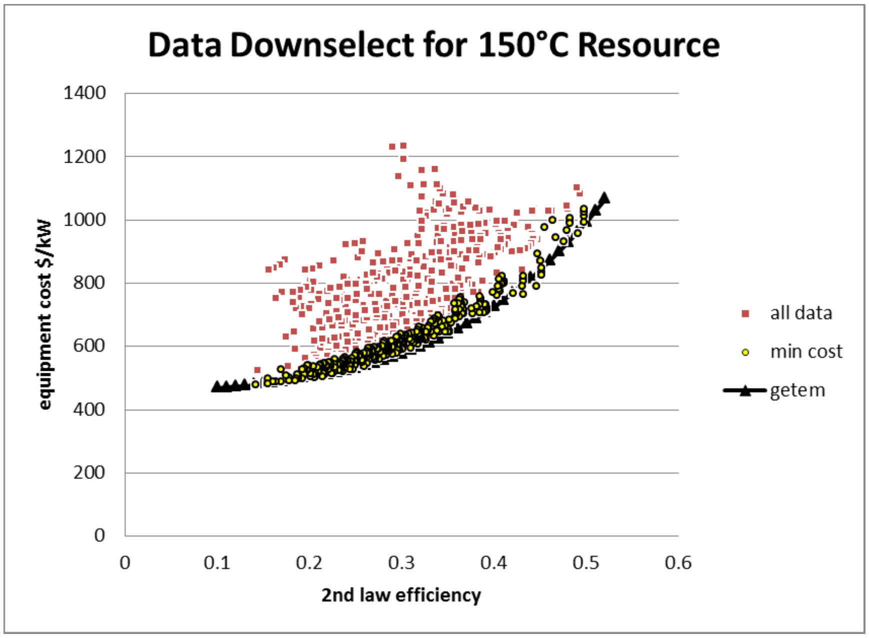
The working fluid pump costs scale with size:

$$\text{cost}_{\text{WF pump}} = \left(\frac{\text{size necessary}/\text{\# modular units}}{\text{10 MW}}\right)^{\text{WFPSF}} \times \left(\frac{10{,}000 \times \text{cost}_{\text{10 MW WF pump}}}{\text{size necessary}/\text{\# modular units}}\right)$$

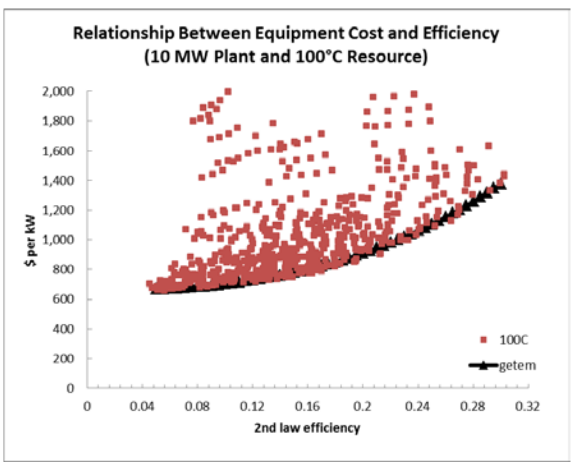
The scaling factor for the working fluid pumps (WFPSF) is given in terms of the resource temperature (°C).

$$\text{WFPSF} = 3.872 \times 10^{-7}\left({T_{gf}}^{3}\right) - 0.00019008\left({T_{gf}}^{2}\right) + 0.029802\left(T_{gf}\right) - 0.7779$$

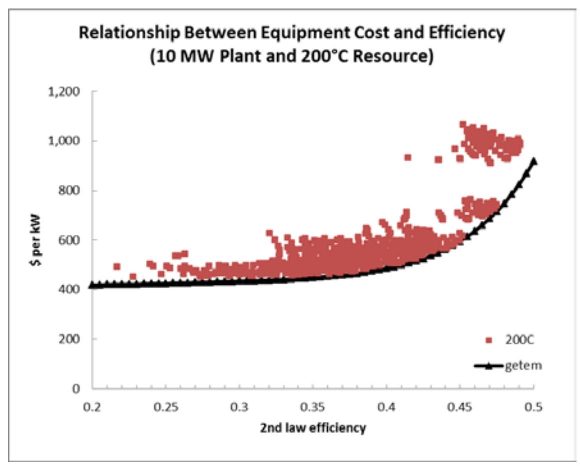
The correlations used in GETEM to estimate the major equipment costs are based on those equipment costs for the minimum cost scenarios for the resource temperatures evaluated. The correlations that were developed were used to estimate the equipment costs for a 10 MW plant at a specified resource temperature. Figure A-34 shows the effectiveness of using this method to approach those minimum costs for 100°, 150°, and 200°C resources.



(a)



(b)



(c)

Figure A-34. GETEM's minimum equipment cost estimates as functions of second law efficiency for a 150°C resource (a), a 100°C resource (b), and a 200°C resource (c).

Except at the higher levels of performance with the 200°C resource, the correlations that were developed to determine the major component costs provided estimates that, when summed, provided reasonable approximations of the minimum costs at a given level of performance.

With this approach, the major component costs are determined for the plant size needed for the power sales in the year for which the LCOE estimate is being made.

To get the installed plant cost, the installation multiplier is determined using an approach similar to that used for the flash steam power plant.

Total Air-Cooled Binary Plant Cost

Using an approach that is analogous to that in the EPRI report (EPRI 1996), a multiplier is applied to these costs to get a total installed cost at the start of operation.

$$\text{installed plant cost} = \text{installation multiplier} \times \sum\left(\text{cost}_{\text{major equipment}}\right)$$

The installation multiplier is determined as:

$$installation\ multiplier = multiplier_{direct\ construction}(1 + indirect\ cost\ multiplier)$$

Both the direct construction multiplier and the indirect cost multiplier are specified inputs. The default value for the direct construction multiplier is determined using an approach based on IPE estimates for air-cooled binary power plants. The multiplier consists of the following:

- Other materials
- Labor
- Other construction (on-site construction management/supervision, construction expendables, and rentals)
- Tax
- Freight.

The other materials include the cost of steel, piping, concrete, electrical equipment, instrumentation, insulation, paint, buildings, and similar things needed for plant construction. The value used is derived from the IPE estimates. Those estimates indicated this multiplier was approximately 1.7 in the plant scenarios modeled.

$$\text{total materials multiplier}_{2002} = 1.7$$

This value is based on major equipment cost estimates in 2002 dollars. To account for the effect of changes in these equipment costs over time, an effective PPI for the major components is determined and used to adjust for the impact that the individual contributors have to the direct construction cost multiplier.

$$major\ component\ cost\ adjustment, or\ MCCA = \frac{\sum major\ component\ cost}{\sum major\ component\ cost_{2002}}$$

This adjustment is applied to the 2002 total materials multiplier and the PPIs for steel and other materials to determine the multiplier to be applied to the major component costs in the year of interest to obtain the total material cost for the binary plant.

$$\text{total materials multiplier} = 1 + \left[\frac{\text{steel multiplier}_{2002}(\text{PPI}_{\text{steel}}) + \text{other multiplier}_{2002}\left(\text{PPI}_{\text{process equipment}}\right)}{\text{MCCA}}\right]$$

In the 2002 estimates, the total materials multiplier was 1.7. The major equipment contribution was 1. The steel contribution was ~0.22. The “other” contribution was 1.7 −1 −0.22, or 0.48.

$$total\ material\ costs = total\ materials\ multiplier \times \sum major\ component\ cost$$

In 2002, the direct labor contribution to the direct construction multiplier was 0.27, with fringe and benefits being 45% of the labor cost:

$$direct\ labor\ multiplier_{2002} = 0.27$$

In the year of interest, the multiplier is:

$$\text{labor multiplier} = \text{direct labor multiplier}_{2002}\left(\frac{\text{PPI}_{\text{labor}}}{\text{MCCA}}\right) \times (1 + \text{fringe multiplier})$$

The contribution of construction supervision, expendables, and rentals to the installation multiplier is based on the IPE estimates as well, and was also approximately constant for these costs in 2002.

$$\text{other construction multiplier}_{2002} = 0.25$$

In the year of interest, the multiplier is

$$\text{other construction multiplier} = \text{other construction multiplier}_{2002}\left(\frac{\text{PPI}_{\text{process equipment}}}{\text{MCCA}}\right)$$

The taxes and freight rates are default inputs that can be modified by GTO on the *DEFAULT Inputs* worksheet. They are applied to the material costs and the other construction costs (not to labor).

The direct construction multiplier is:

$$\begin{aligned}\text{multiplier}_{\text{direct construction}} = \; & \text{labor multiplier} + \text{total materials multiplier}(1 + \text{tax} + \text{freight}) \\ & + \text{other construction multiplier}(1 + \text{tax} + \text{freight})\end{aligned}$$

The indirect costs for the plant construction includes engineering, home office, startup, and other activities not directly associated with plant construction. They are determined using a specified input of the fraction of the direct construction costs. (Note that engineering is assumed to be 50% of these indirect costs; in the project schedule, half of these engineering costs are incurred before obtaining the PPA.) The total installation multiplier is:

$$\text{installation multiplier} = \text{multiplier}_{\text{direct construction}}(1 + \text{indirect cost multiplier})$$

Again, the total plant cost is:

$$\text{installed plant cost} = \text{installation multiplier} \times \sum\left(\text{cost}_{\text{major equipment}}\right)$$

Example:

- Major component costs in 2002 or $\sum PPI(cost_{major\ equipment}$: \$7,000,000
- Major component costs (in year of interest): \$10,000,000
- Major component cost adjustment (MCCA): 1.4286
- Direct labor $_{2002}$: 0.27
- Fringe: 0.45%
- Other construction $_{2002}$: 0.25
- Steel PPI: 1.5
- Process equipment PPI: 1.4
- PPI labor: 1.4
- Labor multiplier: 0.27*(1+0.45)*($^{1.4}/_{1.4286}$) = 0.348
- Other construction multiplier: 0.25*($^{1.4}/_{1.4286}$) = 0.245
- Total materials multiplier: 1+[0.22*1.5+0.48*1.4]/1.4286 = 1.701
- Taxes: 0.06
- Freight: 0.05
- Indirect Costs: 12%
- $Multiplier_{direct\ construction}$ = 0.348 + 1.701*(1+0.06+0.05)+0.245*(1+0.06+0.05) = 2.489
- Installation multiplier = 2.67*(1+0.12) = 2.79
- Installed plant cost = 2.79 * \$10,000,000 = \$27,900,000

The installed plant cost is calculated using both specified and default inputs, reported in $/kW of net plant output. Note this is not per kW of sales, but kW of net plant output (sales plus the geothermal pumping required). The value that is calculated can be revised.

Determination of Binary Plant Cost and Performance

As indicated, the component costs (and hence the installed plant cost) for the binary plants increase as the performance metric second law efficiency (or brine effectiveness) increases. With this increase in performance, the amount of geothermal fluid needed to produce a specified level of sales decreases. This reduces the number of wells that must be drilled, as well as the geothermal pumping required. At some point, the increased plant costs offset the decrease in well costs and geothermal pumping. That is illustrated in Figure A-35 below for a plant with 30 MW of sales.

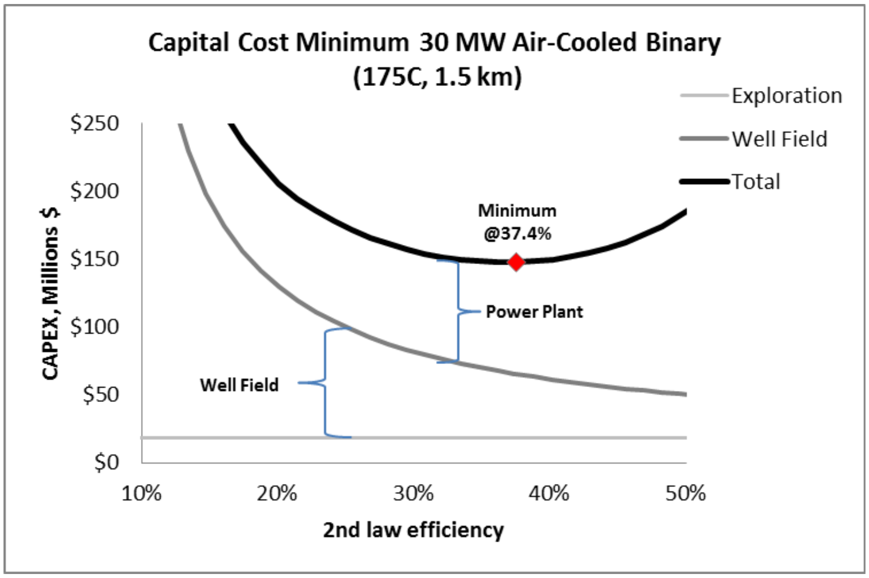


Figure A-35. Example of binary plant efficiency producing capital cost minimum for a scenario with fixed power sales (30 MW).

In GETEM, the exploration cost is effectively a fixed total cost that varies little with the plant performance. As indicated in Figure A-35, the well field costs decrease as the efficiency increases, and fewer wells are required. Though this figure shows power plant costs increasing at the higher efficiencies, the plant costs go through a minimum as well at low plant efficiencies where a larger plant is required to provide the pumping power necessary for the geothermal fluid. This optimal plant performance is less obvious with scenarios in which the number of production wells is fixed. Figure A-36 below shows the capital costs as a function of performance for the same resource conditions and four production wells.

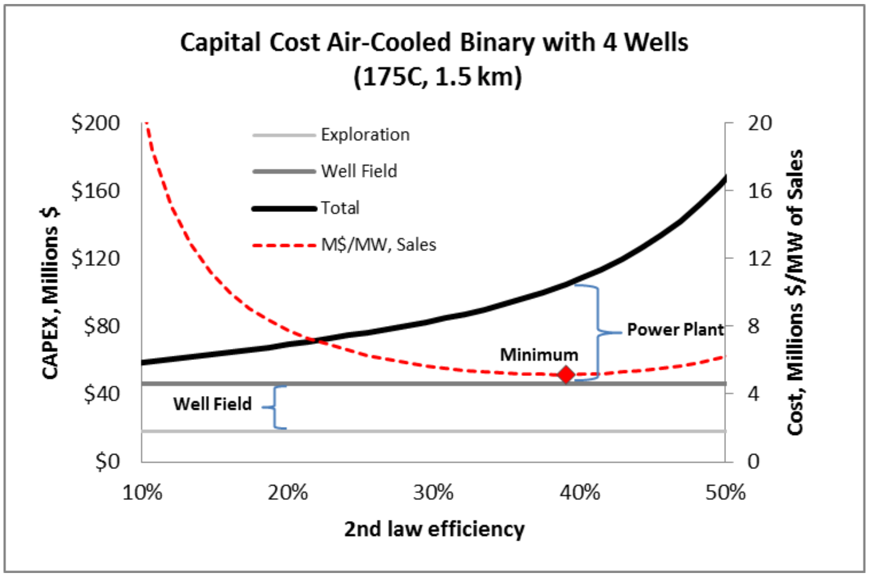


Figure A-36. Example of binary plant efficiency producing capital cost minimum for a fixed number of production wells (four).

With the number of wells fixed, the well field costs are fixed and not impacted by performance. The total plant costs increase with increasing performance, as does the amount of sales (not shown in figure). Sales increase linearly with the performance metric (i.e., for the fixed flow, a plant with a 40% second law efficiency will produce twice the power (and sales) as a plant with a 20% second law efficiency). Because of this linear relationship, the capital cost in terms of $ per MW of sales goes through a minimum as shown.

Figure A-37 below shows the contributions to the LCOE for these two scenarios.

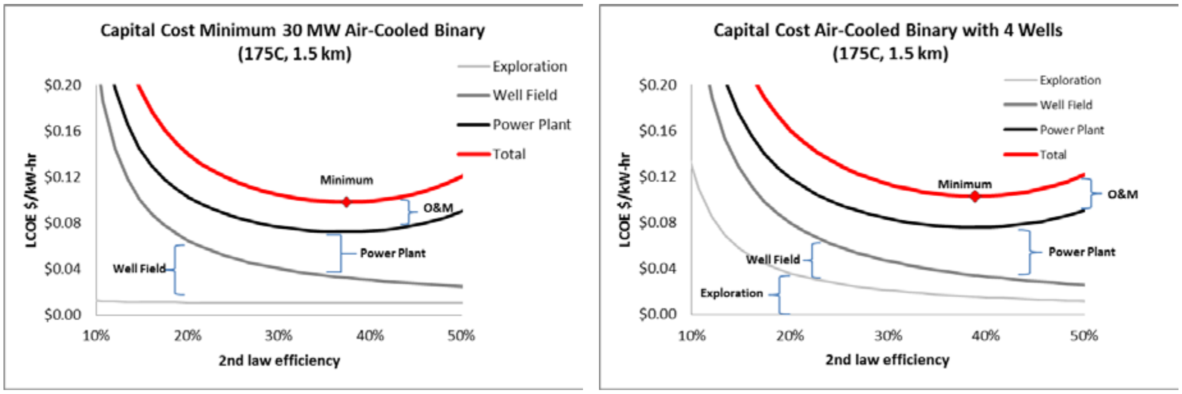


Figure A-37. Capital cost minimum for a 30 MW air-cooled binary plant (left) and for a similar plant with four wells (right).

Both scenarios produce an LCOE minimum. Though the well field and exploration capital costs are fixed with the scenario having four production wells, their contribution to the LCOE does vary, becoming less significant as the plant performance increases and more power sales are produced. Though it is not readily apparent, the level of plant performance producing the LCOE minimum is slightly different for these two scenarios, with the optimal performance being higher for the scenario with four wells, which has a lower level of sales.

A macro is used that varies the brine effectiveness (second law efficiency) until the calculated LCOE is minimized. This is the GETEM default. For a revised scenario, running the macro (once all input revisions are made) will establish the level of plant performance that produces a LCOE minimum for the specified scenario. There are two locations from which the macro can be run: the *Start Here* and *Binary A1* worksheets. This macro uses Excel's Solver function, so this add-in must be active. If a brine effectiveness is been specified, that value will be used in determining plant size and cost, as well as the size and cost of the well field. In this case, the macro will attempt to run, but the LCOE will be based on the inputted value.

It is important to note that the estimates of cost and performance for the power plant are not dependent upon the working fluid or design conditions for the binary plant. They are based on the defined resource temperature, the estimated temperature loss in production wells, a 10°C ambient temperature, the power sales, and the number of modular units. The assumption is made that the plant that will be used will be designed to provide a given level of performance at the minimal cost. The cost estimated is the total installed cost (including any startup costs for the plant).

Transmission Line

Though GTO has not included transmission line costs in its LCOE analysis, there is an option to include them. The method originally used to estimate transmission costs were adapted from a presentation at a Pacific Gas and Electric Company stakeholder meeting (PG&E 2009). This approach and the transmission line base cost are found online at the California Independent System Operator website; this site has archived costs from participating transmission owners from 2009 through the current year.

Using this approach, the costs (in 2015 Dollars) for a new line are:

Base: rural, flat terrain, ≥10 miles, ≤115 kV =$575K

suburban =	*1.2 X Base*
urban =	*1.5 X Base*
hilly terrain =	*1.2 X Base*
mountainous terrain =	*1.3 X Base*
forested terrain =	*1.5 X Base*
4 to 10 miles =	*1.5 X Base*
<4 miles =	*2 X Base*
>115 kV =	*$1,795K*

The costs for ≤115 KV are for wooden pole structures; the higher voltage costs are for a single-circuit, tubular steel poles.

GETEM has a single set of options available: ≤115 kV, flat terrain, and rural population. The transmission line distance is specified.

A12: GEOTHERMAL FLUID PROPERTIES

The LCOE determination requires the project sales to be quantified over the project life. The sales are based on estimates of performance that use properties of the geothermal fluid. It is assumed for the performance estimates that the geothermal fluid is a liquid in the reservoir, and that its properties can be represented by the properties of water. While there are Excel add-ins that provide water properties, these add-ins have a cost and may not be readily accessible by all users.

To provide the needed water properties, specific property values from NIST's RefProp were curve-fitted as a function of another property—generally, temperature and/or pressure. While the property relationships developed allow the necessary performance calculations to be made, they are approximations and should not be represented as the properties of geothermal fluid.

General Equations for Saturated Liquid Water

Nearly all the property correlations used in GETEM are based on the property of saturated liquid water. These correlations are curve fits of the saturated water property predictions from NIST's RefProp, where the property is generally a function of temperature in °F. The relationships used have the form:

$$property = C_6(T)^6 + C_5(T)^5 + C_4(T)^4 + C_3(T)^3 + C_2(T)^2 + C_1(T) + C_0 \text{ , where}$$

Saturated Water (40 - 500F)								
		C6	C5	C4	C3	C2	C1	C0
Pressure	psia		-2.55175E-12	2.41218E-08	-9.19096E-06	0.001969537	-0.19788526	8.0894107
enthalpy	btu/lb	1.01226E-14	-1.88058E-11	1.49248E-08	-5.97605E-06	0.001346286	0.8382772	-24.113935
entropy	btu/lb-R	7.39915E-18	-1.29452E-14	8.84301E-12	-1.84191E-09	-1.20262E-06	0.002032431	-0.0600896
specific vo	ft^3/lb	1.40682E-18	-2.69957E-15	2.17758E-12	-9.15282E-10	2.2418E-07	-2.3968E-05	0.017071
Cp	btu/lb-F	1.38098E-16	-2.18187E-13	1.42033E-10	-4.65228E-08	8.65998E-06	-0.00080616	1.02617
T	ft^3/lb	-9.0287E-10	3.4638E-07	-5.4475E-05	0.00456759	-0.226287	7.7497	134.575
k	btu/hr-ft-F	-5.62597E-18	1.09949E-14	-9.73487E-12	5.19477E-09	-2.64887E-06	0.000829554	0.30074

The curve fit for viscosity of liquid water has a different form:

$$viscosity = 407.22(T)^{-1.194} \text{ , in units of } (^{1bm}/_{ft\text{-}hr})$$

Corrections for Subcooled Water

Subcooled water properties are used primarily in calculations of pressure drop and heat loss in the well bore. Those properties are found using the following relationship:

$$\frac{property}{property_{saturation}} = a(T)^b \times \left(\frac{pressure}{pressure_{saturation}} - 1\right) + 1 \text{ , where}$$

	Pressure Correction	
	a	b
density	7.15E-19	5.91303
Cp	-1.9E-20	6.572584
viscosity	4.02E-18	5.736882
k	3.23E-18	5.72658

These corrections are used primarily in calculating Reynolds numbers, which are used in determining Darcy friction factors and convective heat transfer coefficients in the well bore. The corrected properties will typically more closely approach the RefProp properties with lower temperature fluids. The properties estimated using this approach are generally within 5% or less of those estimated with RefProp with temperatures and pressures below ~250°C and ~700 bar. At higher temperatures and pressures, the deviation from the RefProp increases.

In calculating the available energy of the geothermal fluid, it is necessary to have the enthalpy and entropy of water at 1 atm. Those properties are determined using the polynomial curve fit used for saturated properties and the constants below.

Water at 1 atm, 14.7 psia (35-210F)								
		C6	C5	C4	C3	C2	C1	C0
enthalpy	btu/lb					0.00001087	0.997066497	-31.769589
entropy	btu/lb-R			-4.355E-12	4.39043E-09	-2.66515E-06	0.002201825	-0.067875

Flash Steam Plants

The properties of saturated liquid water with any necessary pressure correction are utilized to estimate performance for all aspects of GETEM's calculations except for the flash plant. In the flash plant, it is necessary to have both the properties of the liquid and vapor phase over a wide range of pressures and temperatures. To estimate these properties with some degree of accuracy, it is necessary to curve-fit the properties over ranges of pressures and temperatures, and use those curve fits that match the conditions for which the properties are needed.

Again, the curve fits are developed using NIST RefProp predicted properties for water. A polynomial curve fit is used having the form:

$$property = C_6(T)^6 + C_5(T)^5 + C_4(T)^4 + C_3(T)^3 + C_2(T)^2 + C_1(T) + C_0$$

The following series of tables (Table A-8) provides the constants used in the expressions for the different property estimates used in the flash steam plant calculations.

Table A-8. Constants used in the expressions for different geothermal fluid property estimates.

Pressure = f(T) in psia							
Temperature Range	**C6**	**C5**	**C4**	**C3**	**C2**	**C1**	**C0**
<125°F	9.97153E-15	1.68375E-11	1.13502E-09	3.41917E-07	1.84319E-05	1.11108E-03	0.021248
125°F<T<325°F	-2.80188E-14	4.34771E-11	-6.75074E-09	1.58988E-06	-9.09892E-05	6.00322E-03	-0.060792
325°F<T<675°F	2.4303E-13	-6.62939E-10	7.68058E-07	-4.53695E-04	0.150475	-26.49	1934.47
>675°F	7.261395E-13	-2.16551E-09	2.698676E-06	-1.765175E-03	0.6471745	-125.9218	10153.58

Enthalpy, liquid= f(T) in btu/lbm							
Temperature Range	**C6**	**C5**	**C4**	**C3**	**C2**	**C1**	**C0**
<125°F	—	—	-4.480902E-10	2.0320904E-06	-3.4115062E-04	1.0234315	-32.479184
125°F<T<325°F	—	—	2.5563678E-10	7.3480055E-08	-2.7703224E-05	0.9998551	-31.760088
325°F<T<675°F	—	5.86342635E-11	-1.3378774E-07	1.22276027E-04	-0.05537374609	13.426933583	-1137.0718729
>675°F	—	3.70216131E-05	-0.12714518982	174.6587566	-119960.00955	41194401.715	-5658291651.7

Enthalpy, vapor= f(T) in btu/lbm							
Temperature Range	**C6**	**C5**	**C4**	**C3**	**C2**	**C1**	**C0**
<125°F	—	—	-7.2150559E-10	-1.5844187E-07	-3.0268712E-04	0.441485808	1061.09961
125°F<T<325°F	—	—	-5.0353897E-10	-5.1596853E-07	9.90060189E-05	0.42367961566	1061.9537518
325°F<T<675°F	-4.9118123E-13	1.36980213E-09	-1.5842735E-06	9.69633804E-04	-0.3315780568	60.38391862	-3413.791688
>675°F	—	-4.8138034E-05	+ 0.1653131591	-227.07686319	155953.29919	-53551582.984	7355226428.1

Entropy, liquid= f(T) in btu/lbm-°R							
Temperature Range	**C6**	**C5**	**C4**	**C3**	**C2**	**C1**	**C0**
<125°F	—	—	—	2.964634E-09	-2.499642E-06	0.002195168	-0.06778459
125°F<T<325°F	—	—	-9.593628E-13	2.223552E-09	-2.16312E-06	0.00215356	-0.06615222
325°F<T<675°F	5.297508E-16	-1.495185E-12	1.739088E-09	-1.064881E-06	3.612208E-04	-0.06296176	4.729245
>675°F	1.100136E-10	-4.450574E-07	7.501037E-04	-0.674174	340.7939	-91866.44	10317090

Entropy, vapor= f(T) in btu/lbm-°R							
Temperature Range	**C6**	**C5**	**C4**	**C3**	**C2**	**C1**	**C0**
<125°F	—	—	2.38219E-11	-2.213415E-08	0.00001113945	-0.004205795	2.312154
125°F<T<325°F	—	—	8.392618E-12	-1.361597E-08	9.334758E-06	-0.004032959	2.305898
325°F<T<675°F	-8.283605E-16	2.333203E-12	-2.708314E-09	1.65401E-06	-5.589582E-04	0.09784205	-5.19791
>675°F	-1.41418E-10	5.720121E-07	-9.639254E-04	0.8662219	-437.8104	118002.2	-13250460

Specific volume, vapor= f(T) in ft³/lbm							
Temperature Range	**C6**	**C5**	**C4**	**C3**	**C2**	**C1**	**C0**
<125°F	4.5215227E-09	-2.7557218E-06	0.00071596466	- 0.1033793	8.9931223	-464.41472	11678.605
125°F<T<325°F	1.1909478E-11	-1.8270648E-08	1.1692082E-05	-4.0132715E-03	0.78482148	- 83.834081	3890.919
325°F<T<675°F	8.187709E-15	-2.7284644E-11	3.7948334E-08	-2.8277928E-05	0.011958041	-2.7389634	268.32894
>675°F	—	—	-8.7731388E-09	2.3582903E-05	-0.023769687	10.645163	-1786.8983

Temperature= f(P,psia) in °F							
Pressure Range	**C6**	**C5**	**C4**	**C3**	**C2**	**C1**	**C0**
<2 psia	-7.18640668	63.30476138	-222.3098297	400.5726943	-403.5629735	255.8563258	14.788
2<P<20 psia	-1.2178122E-05	9.43580389E-04	-0.0297343763	0.4946879155	-4.801670172	31.49104908	78.872
20<P<200 psia	-1.287831E-11	1.0530967E-08	-3.4988476E-06	6.12922921E-04	-0.062604067	4.368874775	161.409
200<P<1000 psia	-4.3371352E-16	1.88671656E-12	-3.4275245E-09	3.40481648E-06	-2.0724713E-03	0.9305613192	256.297
>1000 psia	-3.2288676E-19	4.5896969E-15	-2.7823504E-11	9.44074178E-08	-2.0256474E-04	0.333459111	342.906

In relating the specific volume of saturated water vapor to pressure, two different correlations are used (dependent upon pressure). For higher-pressure vapors, the following is used:

$$\text{specific volume}_{\text{vapor}} = C_6(P)^6 + C_5(P)^5 + C_4(P)^4 + C_3(P)^3 + C_2(P)^2 + C_1(P) + C_0 \text{ , where}$$

Specific volume, vapor= f(P,psia) in ft³/lbm							
Pressure Range	**C6**	**C5**	**C4**	**C3**	**C2**	**C1**	**C0**
200<P<1000 psia	4.07239263E-17	-1.7199693E-13	2.98853804E-10	-2.7579166E-07	1.45475053E-04	-0.0438346609	7.01332874
>1000 psia	-8.2949288E-21	8.10943127E-17	-2.8059086E-13	3.05379716E-10	4.5750427E-07	-0.00155021959	1.44118272

At lower pressures, the following is used:

$$specific\ volume_{vapor} = a(P)^b \text{ , where}$$

Specific volume, vapor= f(P,psia) in ft³/lbm		
Pressure Range	**a**	**b**
<2 psia	333.81229512	-0.94402159016
2<P<20 psia	332.15976378	-0.93664745606
20<P<200 psia	-1.287831E-11	-0.94294510344

These properties are the basis for determining the flash plant performance and equipment sizes used to determine the plant cost. The flash plant performance is the basis for sizing the well field, or for establishing the amount of power sales from a fixed number of wells for a defined resource scenario.

Impact of GETEM Properties on LCOE

A recent version of GETEM was modified to determine all fluid properties using a RefProp add-in to Excel instead of the different correlations described. Two hydrothermal resource scenarios were considered, one using a binary plant and the other a flash steam plant.

The resource defined that utilized the binary plant was at 175°C and a depth of 1.5 km. The resource using the flash steam plant was at 250°C and 2.5 km. The binary plant had sales of 30 MW; the flash plant had sales of 40 MW. The following summarizes the impact of using the correlations in GETEM to estimate water properties.

Table A-9. The impact of using GETEM's correlations for water properties on important project metrics.

	BINARY		FLASH STEAM	
Parameter	GETEM Properties	RefProp	GETEM Properties	RefProp
Sales (MW)	30	30	40	40
Plant size (MW)	34.373	34.301	41.808	41.813
Number of successful production wells	6.19	6.17	4.80	4.80
Total GF flow (kg/s)	618.7	617.4	384.1	384.0
Temperature loss in well (°C)	1.35	1.35	3.37	3.37
Total overnight cost (million $)	$162.724	$162.373	$152.214	$152.245
PV of power over life (MW · hrs)	2,726,853	2,727,773	3,622,622	3,622,078
LCOE ($/kW · h)	$0.0984	$0.0982	$0.0685	$0.0686

Comparing results for the two resource scenarios indicate that, while the GETEM properties are only approximations, their use did not substantially impact the performance or costs obtained.

Silica Temperature Limit

It is assumed that a minimum temperature limit is placed on the geothermal fluid to prevent mineral precipitation—specifically, the precipitation of amorphous silica. This temperature limit is used when setting operating constraints on flash pressures for steam plants, and, if imposed, can impact the calculation of the injection pumping power. Though it is not specifically applied in any of the binary plant calculations in GETEM, it was imposed during the Aspen modeling that is the basis for the cost and performance calculations in GETEM. With binary plants, it may be imposed when estimating the temperature of the injected brine.

In early versions of GETEM, the temperature constraint was determined using expressions for the solubility temperature of amorphous silica based on correlations reported by Fournier (1981). These relationships were used to relate the solubility temperature of amorphous silica to a resource temperature, assuming that the silica went into solution either as quartz or as chalcedony.

$$\textbf{quartz: } T_{amorphous\ silica} = 0.000658(T_{resource}{}^{2}) + 0.712233(T_{resource}) - 93.2874$$
$$\textbf{chalcedony: } T_{amorphous\ silica} = 0.000148(T_{resource}{}^{2}) + 0.774255(T_{resource}) - 70.4349$$

In both of these expressions, temperatures (T) are in °C. In GETEM, the correlation based on chalcedony solubility was used for resource temperatures below 180°C. The correlation based on quartz solubility was used for resource temperatures of 180°C and higher.

These expressions were used in the modeling of the binary plants, the results of which are the basis of GETEM's estimates for these air-cooled plants. Their use produced a discontinuity in the limit as shown in Figure A-38 below.

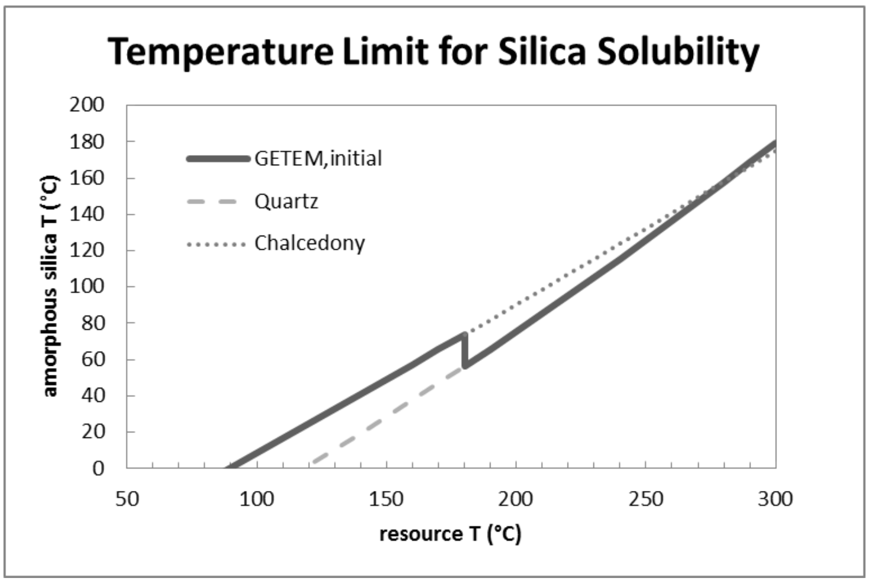


Figure A-38. Amorphous silica solubility temperatures used in early versions of GETEM.

The discontinuity that occurs when switching between the two solubility curves produced similar discontinuities in GETEM's calculations.

To resolve this, the approach for characterizing this temperature limit was revised. Correlations from Gunnarsson and Arnorsson (2000) were used to develop the following expressions for the solubility of quartz and amorphous silica.

$$SiO_{2_{quartz}} = -1.334837 \times 10^{-7}(T_R{}^{4}) + 7.065845 \times 10^{-5}(T_R{}^{3}) + 3.62948 \times 10^{-3}(T_R{}^{2}) + 0.367242(T_R) + 4.2059$$

$$T_{qAmorphous\ silica} = 2.49634 \times 10^{-11}\left(SiO_{2_{quartz}}{}^{4}\right) - 4.25191 \times 10^{-9}\left(SiO_{2_{quartz}}{}^{3}\right) - 1.19669 \times 10^{-3}\left(SiO_{2_{quartz}}{}^{2}\right) + 0.307616\left(SiO_{2_{quartz}}\right) - 0.2944$$

In these relationships, temperature (T) is in °C. The amount of silica ($SiO_{2\,quartz}$) is the silica concentration in solution (ppm). The correlations upon which these relationships were derived were determined for a temperature range from 8° to 310°C. Use of these relationships produce a single curve for the solubility of amorphous silica without discontinuity as shown in Figure A-39 below.

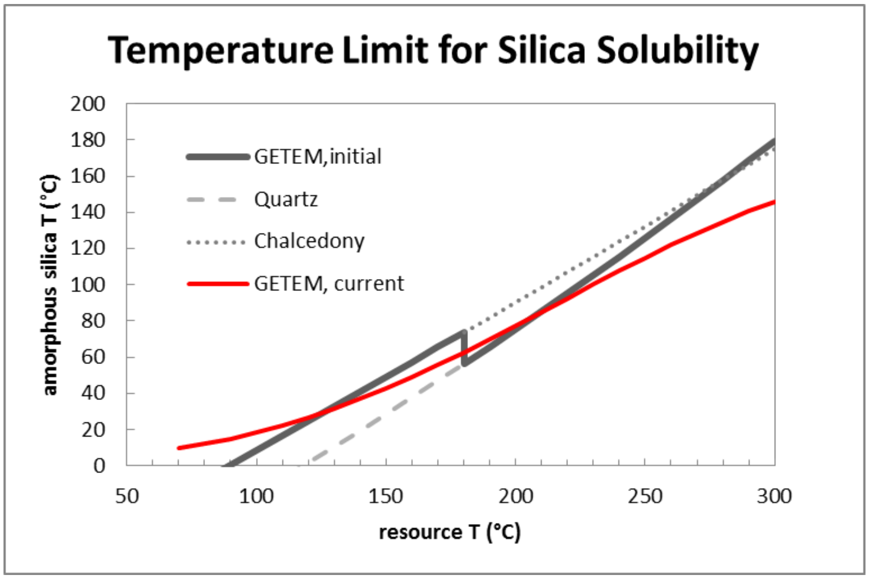


Figure A-39. Current and prior GETEM estimates of amorphous silica solubility temperatures.

The calculations that are made in GETEM are intended to be representative of geothermal power production. To do so, it is necessary to approximate the properties of the geothermal fluid. These methods do not produce results that deviate significantly from those obtained when using recognized software to generate the properties needed. Even though the results are favorable for the two resource scenarios considered, there will be instances in which these methods do no work. Those are likely to be higher-temperature resources, resources with higher reservoir pressures, and/or resources having high levels of dissolved solids.

A13: PRODUCER PRICE INDEXES

The costs used to determine an LCOE are derived from several sources, each of which is based on a specific year. In order to utilize these costs, as well as to allow GETEM to estimate costs for a specified year, a cost index is applied to GETEM's base cost estimated. The cost indices used are the Producer Price Indexes (PPIs) obtained from the U.S. Bureau of Labor Statistics. In determining a cost in a specified year, a designated PPI is multiplied by the estimate developed in GETEM.

$$specified\ yr\ cost_n = PPI_n \times GETEM\ estimated\ cost_{base}$$

The PPIs used are tabulated below in Table A-10, along with the GETEM estimates/default inputs to which they are applied.

Table A-10. Producer Price Index categories with reference year and description of application to default costs.

PPI Category	Applied to Default Costs	Reference Year	Comment
Manufacturing Labor	Applied to operation and maintenance labor; used in a discontinued method of estimating binary plant equipment costs.	2002	
Construction Labor	Applied to estimates of labor contribution to direct construction multiplier for both binary and flash steam power plants.	2002	
Engineering	Applied to default well testing costs; used in a discontinued approach for determining indirect costs for plant construction.	2002	
Steel	Applied to estimates of steel contribution to direct construction multiplier for both binary and flash steam power plants (includes piping).	2002	
Pipe	Applied to estimates for field gathering system and production pump casing; used as indicator for increases in casing cost in internal well cost model (not reported).	2002	
Electrical (average used)	PPI for process equipment used.	2002	No longer used
Turbine-Generator	Applied to power plant turbine-generator cost estimate.	2002	
Heat Exchangers	Applied to all estimated heat exchanger costs.	2002	
Pumps	Applied to all power plant cost estimates; applied to injection pump and production pump estimates.	2002	
Process Equipment (average used)	Binary plants: applied to estimates of both the "other" and construction materials contributions to direct construction multiplier. Flash plants: same as binary plus applied to flash vessels, cooling tower, NCG removal, and H2S abatement systems.	2002	
Oil & Gas Well	Adjust cost for small-diameter exploration drilling; adjust default costs for well drilling costs; applied to material elements of internal well cost model (not reported).	2010	
Drilling Services	Applied to estimates for pump installation and well stimulation default cost; applied to services in internal well cost model (not reported).	2010	
Cement	Applied to cement costs in internal well cost model (not reported).	2010	
Legal Services	Applied to permitting costs.	2012	
Oil & Gas Support	Applied to non-drilling exploration costs; applied to "other" costs determined in internal well cost model (not reported).	2010	
Directional Drilling	Applied to directional drilling costs determined in internal well cost model (not reported).	2010	
Chemicals	Applied to treatment costs for cooling tower and geothermal fluid.	2007	
Petroleum Products	Applied to lubrication oil used with line-shaft pumps.	2001	

The PPIs are applied to the model default costs. If a cost input is revised, the PPI is not applied. It is assumed that the inputted value is current for the year being evaluated. If input is revised that is not a cost, the PPIs are applied to the cost estimated using the revised input.

As indicated in Table A-10 above, several of the PPIs are used in an internal well cost model that is currently not used. This method is retained as it could be used by GTO to estimate the relative impact of a drilling technology improvement; those relative improvements could then be applied to the cost estimates generated using the cost curves that are used to estimate well drilling costs.

The Producer Price Indexes, with series identification and index descriptions used are given below in Table A-11.

Table A-11. Producer Price Indexes by GETEM category, with BLS series ID and description.

GETEM Category	Bureau of Labor Statistics Series ID	Index Description
Manufacturing Labor	Series ID: CEU3000000008	Industry: Manufacturing
Construction Labor	Series ID: CEU2023700008	Industry: Heavy and civil engineering construction
Engineering	Series ID: CEU6054134008	Industry: Engineering and drafting services
Steel	Series ID: WPU101	Item: Iron and steel
Pipe	Series ID: PCU332996332996	Industry: Fabricated pipe and pipe fitting mfg.
Electrical (average used)	Series ID: PCU33531-33531	Industry: Electrical equipment mfg.
	Series ID: WPU10260301	Item: Electric wire and cable
	Series ID: WPU1173	Item: Motors, generators, motor generator sets
	Series ID: WPU117929	Item: Miscellaneous electrical industrial apparatus
	Series ID: PCU3353113353111	Industry: Electric power and specialty transformer mfg.
Turbine-Generator	Series ID: WPU1197	Item: Turbine and turbine generator sets
Heat Exchangers	Series ID: WPU1075	Item: Heat exchangers and condensers
Pumps	Series ID: PCU3339113339111Z4	Industry: Pump and pumping equipment manufacturing
Process Equipment (average used)	Series ID: PCU332911332911	Industry: Industrial valve manufacturing
	Series ID: PCU333912333912	Industry: Air and gas compressor manufacturing
	Series ID: PCU334513334513	Industry: Industrial process variable instruments
	Series ID: WPU1061	Item: Steam and hot water equipment
	Series ID: WPU10720135	Item: Metal tanks and vessels, custom fabricated
	Series ID: WPU114902	Item: Metal valves, except fluid power
Oil & Gas Well	Series ID: PCU213111213111	Industry: Drilling oil and gas wells
Drilling Services	Series ID: PCU213111213111P	Industry: Drilling oil and gas wells; Primary services
Cement	Series ID: WPU13220161	Item: Nonmetallic mineral products; Cement
Legal Services	Series ID: PCU5411—5411	Industry: Drilling oil and gas wells; O&G Well directional drilling control
Oil & Gas Support	Series ID: PCU213112213112	Industry: Support activities for oil and gas operations
Directional Drilling	Series ID: PCU21311121311103	Industry: Drilling oil and gas wells; O&G Well directional drilling control
Chemicals	Series ID: WPU061	Industry: Industrial Chemicals
Petroleum Products	Series ID: WPU057	Industry: Petroleum products, refined

These price indexes are not updated automatically. For the most current information, it is necessary to go to the Bureau of Labor Statistics website, download each individual series, and normalize the values to the reference year given in the prior table. The website is http://data.bls.gov/cgi-bin/srgate.

A14: ERROR AND WARNINGS

The *Error-Warnings* worksheet lists potential issues with the input provided. When there is a potential issue, "Error/Warnings" will appear at the top of the worksheets where input is provided. This is a link to the *Error-Warnings* worksheet. The number following this link is the count of the number of potential issues found. When there is an issue, a message will be displayed on the *Error-Warnings* worksheet describing the issue. Adjacent to the message is a link to the location where the input is being questioned.

The following is a list of the current messages followed by possible responses to resolve the issues:

> *The number of production wells inputted is less than the number of successful production wells drilled during Exploration.*

This message occurs if the number of production wells specified is less than the number of successful production wells drilled during exploration. Correct this by changing the number of production wells that the project evaluation is being based upon, or by changing the number of successful wells drilled during exploration. It is also possible to clear the message by reducing the productivity of the production wells (flow rate and/or productivity index) or using a less efficient power plant.

> *The model cannot calculate using a defined Resource Temperature that exceeds the Critical Temperature of Water.*

The properties used in GETEM to estimate performance are limited to temperatures below the critical temperature of water (374°C). The correlations used in GETEM provide reasonable approximations of water properties for temperatures up to ~300°C.

> *The resource depth exceeds the maximum for using the GETEM methodology for well cost.*

GETEM's cost correlations are developed from estimates for depths to 6 km.

> *The power sales specified requires fewer production wells than were successfully drilled during Exploration. Increase sales or reduce the number of successful Exploration wells, the flow per well or the plant performance.*

Increase sales or reduce the number of successful exploration wells. It is also possible to clear this by decreasing the well flow and/or plant performance. This message may accompany other messages.

> *The duration of pre-startup activities exceeds that allowed in GETEM when using the EERE/DCF methodology.*

Reduce the duration of one or more of the pre-operational activities. Up to 14 years total for these activities is allowed for the model.

> *Model cannot evaluate projects operating longer than 40 years.*

This limitation on the project life is inherent to the model; it results from the method used to determine the power production as the resource temperature declines with time.

> *When using Fixed Charge Rate Method, project life for all cases = 30 yr*

This limitation is based on the default fixed charge rate used, which is based on the assumption of a 30-year life.

> *For the scenario defined, the plant output will go to 0 before the end of project life. Clear the warning by either defining more resource potential*

found during Exploration, reducing power sales, decreasing project life or decreasing temperature decline rate.

This message will occur when the specified annual temperature decline is sufficient that the predicted output goes to zero before the end of the stated project life. This can be cleared by reducing the temperature decline rate, the project life, or both. It can also be cleared by changing resource potential and power sales to allow for re-drilling the well field.

The plant net plant output exceeds the potential resource found.

This message is cleared by either reducing the level of sales or increasing the resource potential found at the developed site. When this message occurs, there will be no makeup drilling.

Recommend not Proportioning EGS Exploration Costs with Resource Potential Found.

This message is based on the premise that makeup drilling will be necessary with EGS.

No full-sized wells drilled during Exploration of Hydrothermal Greenfield Project.

To clear this message, either exploration drilling is included for the defined scenario, or the project type is changed to *Field Expansion*.

Exploration drilling is occurring at more sites than were examined during pre-drilling evaluation.

This message can appear when the down-select process for developing a project is used in the evaluation. Either increase the number of sites evaluated or reduce the number of sites with drilling.

Full-sized Exploration wells are drilled at more sites than have small-diameter well drilling.

This message can appear when the down-select process for developing a project is evaluated. Either increase the number of sites at which small-diameter wells are drilled or reduce the number of site where full-sized exploration wells are drilled.

No full-diameter wells are drilled during Exploration of 'Greenfield' project.

Exploration Wells for a Hydrothermal Resource are to be stimulated. If stimulation required, evaluate as EGS resource.

The successful Exploration wells for an EGS Resource are not being stimulated. If no Exploration stimulation is required, evaluate as a Hydrothermal Resource.

The default is that EGS resources are stimulated and that at least one well drilled during the exploration phase be successfully stimulated. If input for the hydrothermal resource indicates wells are stimulated during the exploratio*n* phase, the scenario should be defined as using an EGS resource.

Two successful full-size Exploration wells required for EGS.

This is based on the assumption that EGS requires demonstration of coupled production and injection wells to establish the commercial viability of the resource.

No stimulation failures for Exploration wells.

#Stimulations specified < #successful wells stimulated - Increase number of stimulations and/or revise well type stimulated.

These messages are may occur when evaluating EGS scenarios. The number of wells stimulated during exploration is based upon the number of successful wells drilled and the type of well stimulated. At least one well must be successfully stimulated.

The defined scenario has no injection wells being drilled.

Unless the project evaluated is for a *Field Expansion,* injection wells will be required.

Drilling Success Rate should be >0% and <=100%.

When wells are stimulated, unsuccessful wells are not used to supplement injection. This applied to Hydrothermal as well as EGS resources. If Hydrothermal resource, must indicate which well type is stimulated.

When wells are stimulated, failed wells are not used to supplement injection regardless of the resource type being evaluated. Because the default for hydrothermal resources is that no stimulation will occur, it is necessary to identify whether production wells, injection wells, or both well types are stimulated.

When failed wells are used to supplement injection, their relative productivity should be between 0 and 1.

If the productivity is one or greater, it is not likely the wells would be considered failures.

With pumping, the bottom hole pressure in the injection well is 50%+ higher than the estimated hydrostatic pressure. Consider reducing the flow rate per injection well, and/or increase the Injectivity Index.

The 50% value in this message is arbitrary, intended to provide warning that the pressures used may promote fracturing of the reservoir and/or seismic activity.

Need to use Larger Diameter production well size at the specified resource depth in order to allow for production pump with Binary plant. Minimum casing size 13-3/8 inch

This message occurs if a *Smaller-Diameter* well is specified with binary plant.

Stimulation has been specified with a Hydrothermal Resource scenario.

No stimulation specified with EGS Resource scenario.

These messages apply to the drilling phase. The default is that hydrothermal resources will not be stimulated, while EGS resources will be.

The stimulation success rates should be between 0 and 100%.

Pump efficiency should be >0% & <100%.

Specified success rates and efficiencies should be greater than zero. Specified efficiencies are less than 100 %. Specified success rates can be as high as, but should not exceed, 100%.

Cannot input pump depth with EGS resource - inputted value ignored & calculated pump depth is used if wells are pumped.

Inputting a pump depth with an EGS resource can produce circular reference.

The pump depth exceeds the depth of the resource/production well. The inputted depth needs to be reduced, if calculated, the well flow rate needs to be reduced, or productivity index increased.

When inputted pump depth less than calculated, it is probable that geofluid will flash before getting to binary plant heat exchangers. To decrease calculated depth, decrease well flow or increase Productivity Index.

The calculated pump depth is a function of a number of parameters; the well flow rate and productivity index that are specified are the major contributors to this depth. Decreasing flow rate or increasing reservoir hydraulic productivity will decrease the calculated pump depth.

Any input for water loss or water cost is ignored with Hydrothermal Resource scenarios using air-cooled binary plants.

Pump depth exceeds 2,000 ft limit for specified Lineshaft Pump. Change pump type, change inputted depth or reduce flow/increase productivity index.

Flashing may occur in Production Well or surface piping - OK with Flash Plant. If Binary, use pumped wells or revise inputted pump depth.

With inputted pump depth, flashing is predicted in Production Well or surface piping with a Binary Plant.

The geothermal pumping power exceeds the plant output – define a more efficient plant, decrease flow and/or increase Productivity/Injectivity Index.

If you input the O&M LCOE contribution, you must enter a value for the contributions from both the plant and well field.

Revised Binary Plant Performance exceeds that allowed in GETEM's Cost Correlations.

GETEM's correlations that relate binary cost to plant performance are based on estimated costs for a range of performance at each resource temperature evaluated. The value that is inputted is outside that performance range. GETEM will try to estimate a cost based on the value provided, but that estimate should be considered suspect.

The HP or Single Flash pressure is out of range - it exceeds the estimated wellhead pressure or is less than 1 atmosphere; production well needs to be pumped, the well flow rate reduced or flash pressure revised.

LP Flash pressure exceeds HP Flash Pressure - revise LP Flash pressure.

LP flash pressure is less than 1 atm - reduce well flow rate or use production pumps.

Pressure losses in the production well are only approximations once the geothermal fluid begins to flash. The warnings provided are to advise that there may be a problem with inputted values. GETEM uses the inputs provided for flash pressures (default or revised) and not estimated wellhead pressures.

A15: EXCEL ADD-INS

GETEM is a macro-enabled workbook developed with Microsoft Office Professional Plus 2010 (Version 14.07.7155.5000). The macros in GETEM utilize the Excel add-in Solver, which must be an active application in Excel. To check whether the Solver add-in is active, click on the *File* tab on the menu bar (shown in Figure A-40).

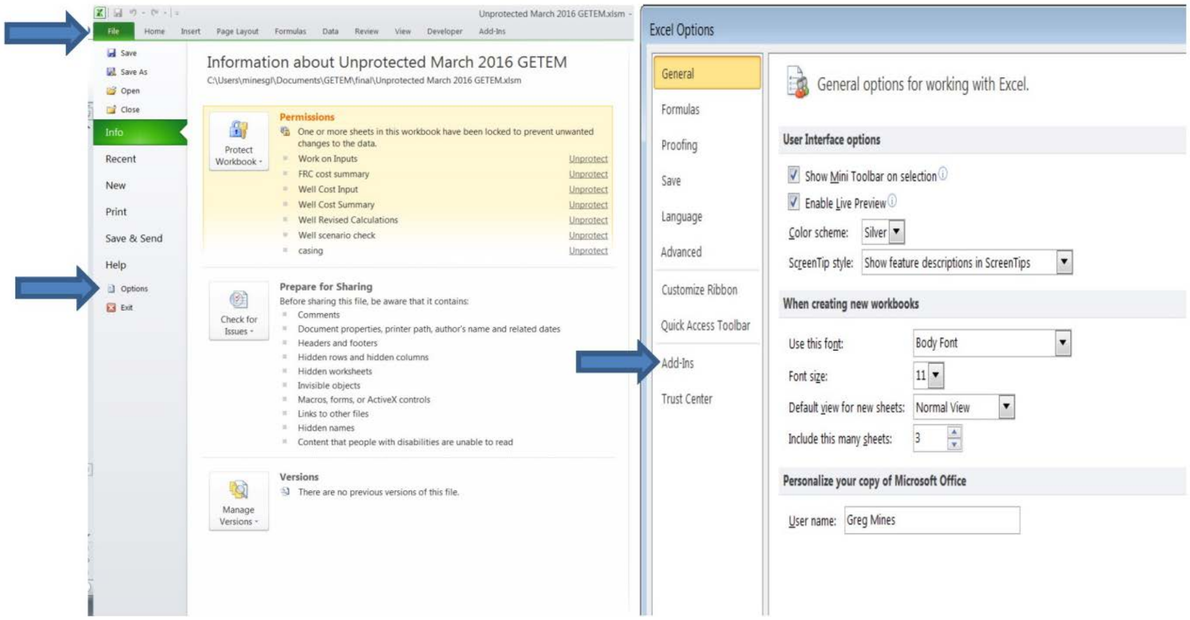


Figure A-40. The *File* tab (top left arrow), *Options* button (bottom left arrow) and *Add-Ins* button (right arrow) in Microsoft Excel.

Next click on the *Option*s button, and the window on the right will open. Click on *the Add-In*s button. The following window, shown in Figure A-41, will open.

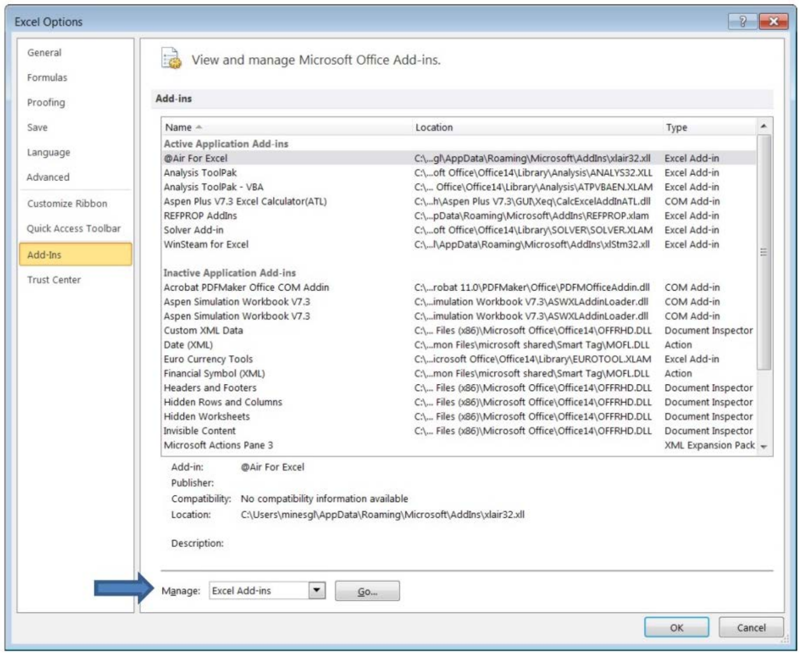


Figure A-41. The add-ins list in Microsoft Excel. Check this list to see if Solver is active.

If *Solver* is not shown as an active application add-in, select the Excel Add-Ins at the bottom of the window and click *Go*, and the following window will appear (see Figure A-42):

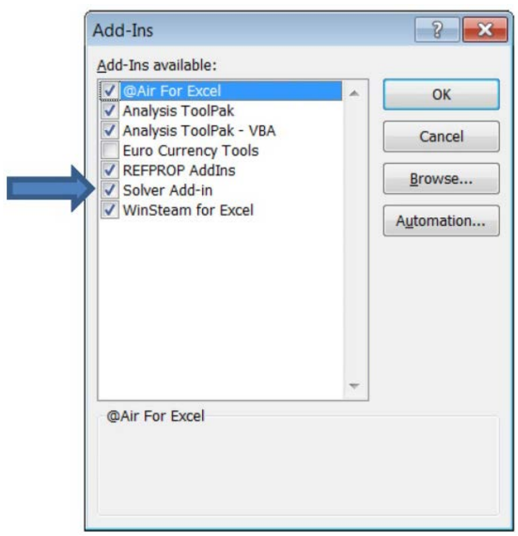


Figure A-42. The menu for add-ins available in Excel.

If the Solver add-in is not checked, click in the box next to *Solver*. If *Solver* does not appear, search for the file “solver.xlam.” Once found, browse from this window and add this file.

If Solver has been added and the macro works, click on the *Developer* tab on the menu bar, then on *Visual Basic* as shown in Figure A-43.

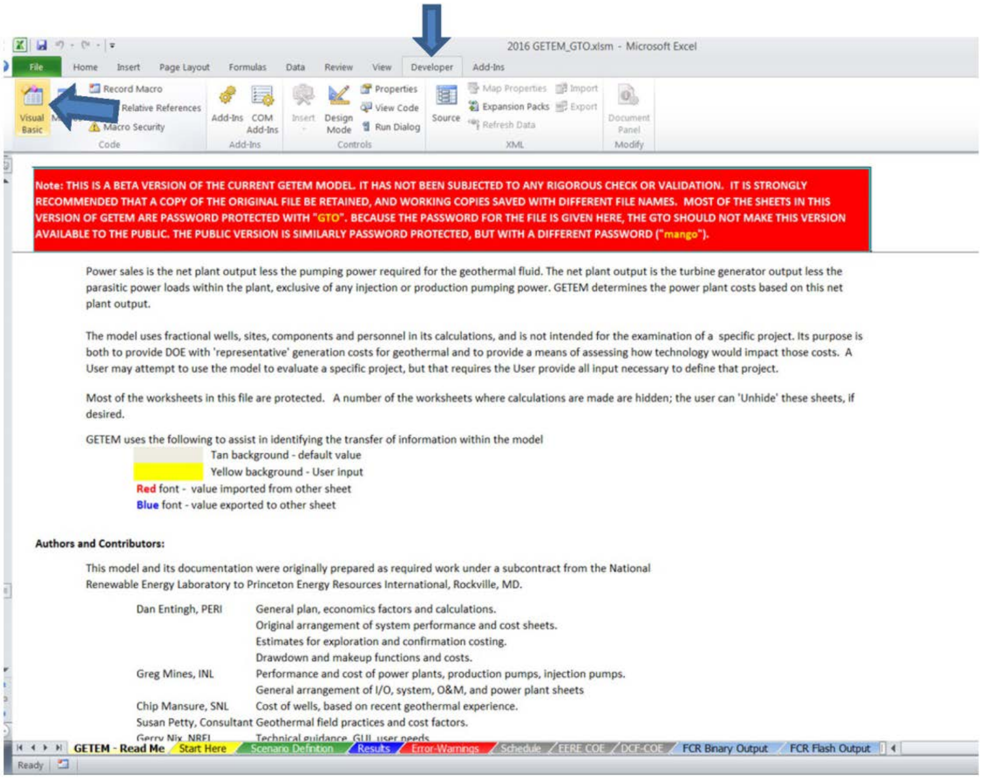


Figure A-43. The *Developer* tab (right arrow) and *Visual Basic* button (left arrow) in Microsoft Excel.

The window in Figure A-44 below will appear. Click on *Tools*, then *References*.

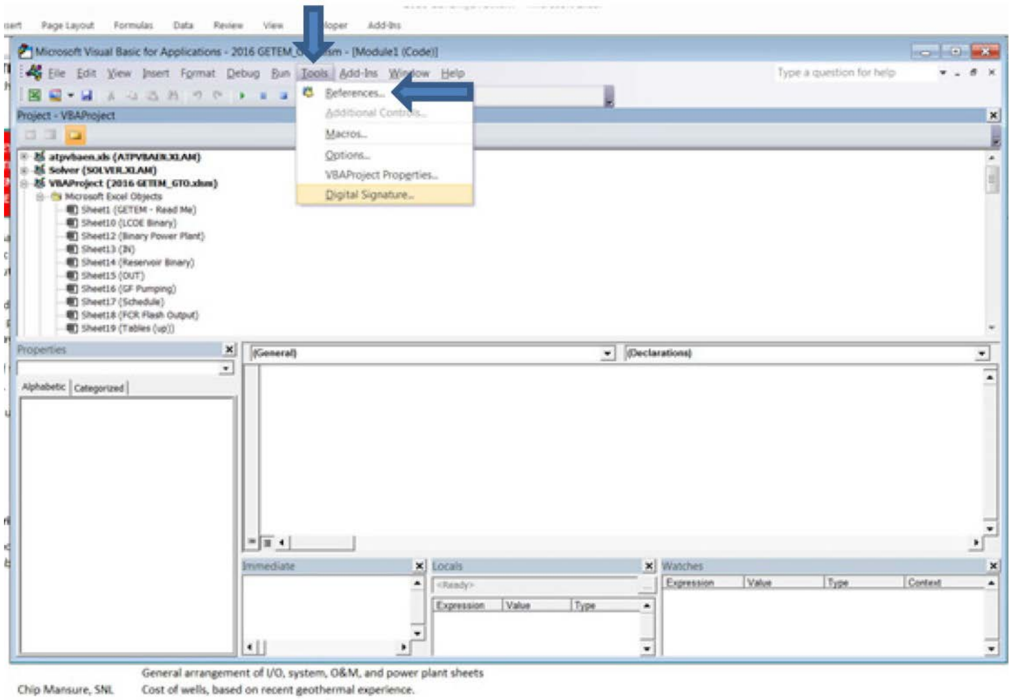


Figure A-44. The *Tools* tab (left arrow) and *References* option in the *Visual Basic* menu.

The window shown in Figure A-45 will open. Confirm the box adjacent to *Solver* is checked; if not, click on the box. Then click "OK."

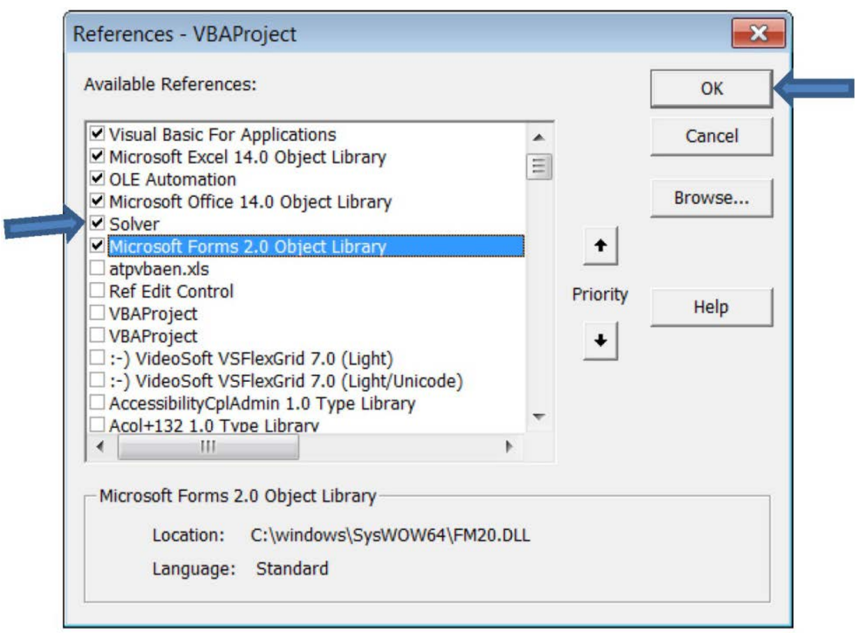


Figure A-45. Box next to *Solver* option. This should be checked.

The macros should work.

Appendix B

Information on GETEM's Reservoir Inputs

Appendix B

Information on GETEM's Reservoir Inputs

B1: WELL PRODUCTIVITY

The flow rate from a production well is utilized in GETEM to determine either the number of wells needed to provide a specified level of sales or the sales that will be achieved from a specified number of production wells. It also impacts the amount of pumping power that is required to support the operation of the power plant. As such, it is one of the more critical values to be defined when evaluating a specific scenario. While the flow rate is unique to both a resource and an individual well, the historical production and injection data submitted by geothermal operators to the Nevada Division of Minerals (NV DoM) provide a basis for establishing representative values for the GETEM defaults.

The plants submitting data to the NV DoM are either binary or flash steam. Generally, production wells that supply flash plants are not pumped, with the geothermal fluid allowed to "flash" in the well bore. In contrast, wells supplying fluid to binary plants are typically pumped.

Production Well Flow

Flash Plants

Figure B-1 shows the number of wells having reported flow and the average flow for each well during the reporting period (1 month).

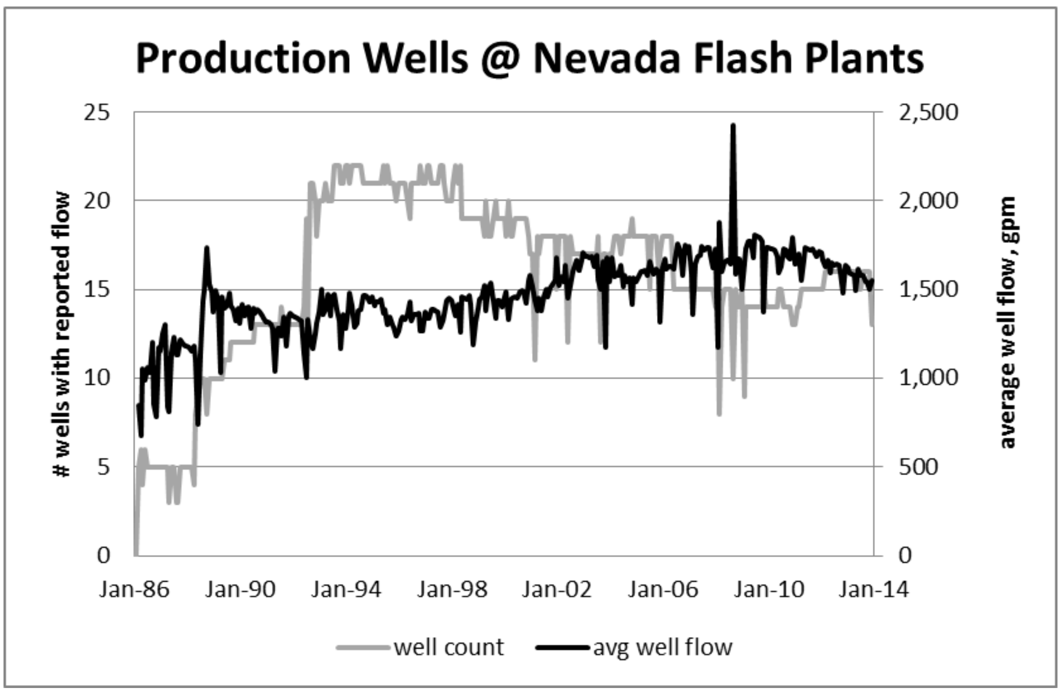


Figure B-1. Number of wells and the average flow for each well at Nevada flash plants.

This figure has the reported data for Beowawe, Desert Peak, Dixie Valley, and Brady; it does not include the data for Steamboat Hills. The data shows that the average flow for the wells in production increased with time, while the number of wells in service has tended to decrease. This decrease in the well count is indicative of having no new flash plants built in NV over the past 20 years. It also reflects the exclusion of the production from Desert Peak after 2006 (when the binary plant came online). The increase in average flow is likely to have resulted from a combination of taking less productive wells out of service (as suggested by the decreased number of wells having reported flow) and increased flow from those wells in service. Increased flow from individual wells could be the result of improved reservoir management, or the consequence of reducing flash pressures to accommodate resource temperature decline.

The distribution of reported flows with time also suggests they have increased over time. Figure B-2 below shows the distribution of reported flow rates by decade. (*After 2010* includes limited data from 2010 to 2014.) In the legend, the value in parentheses is the average flow over that period. Flows tend to be primarily in the range between 800 and 2,200 gpm, with the magnitude of the flows most often reported increasing with time. These distributions would suggest that the average flow rates would be representative of the production well flow for a binary plant.

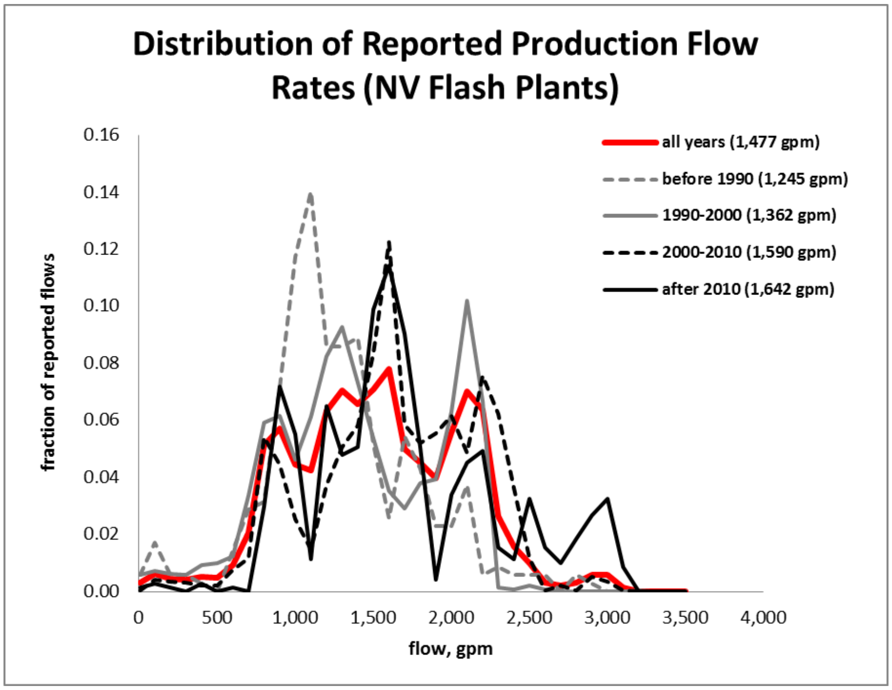


Figure B-2. Distribution of reported flow of Nevada flash plants by decade.

GETEM's default value for flash plant production well flow rates is 80 kg/s; for a 250°C resource, this would be ~ 1,590 gpm. Operators report a volumetric flow rate (gallons per month), and it is not known what fluid temperature provides the basis for this flow. Dick Benoit's recent GRC papers (2014 and 2015) indicate there is some ambiguity in the reported flows because of this temperature uncertainty. If a flow of 80 kg/s is reported in terms of a wellhead temperature postulated to be between 140° and 200°C, the volumetric flow could be in the range of 1,370 to 1,465 gpm. If reported for a density corresponding to 15°C, 80 kg/s would correspond to 1,270 gpm. (It is common for correlations used to relate differential pressure to flow rate to be based on properties at standard conditions.) It is unlikely that the reported flows corresponds to the resource temperature, which would suggest that GETEM's default flow rate is conservative. The most frequently reported flow rate since 2000 is ~1,600 gpm, which is approximately the average value over that period as well. Basing the water properties on the postulated wellhead temperatures, this would correspond to mass flow rates of 87 to 93 kg/s.

Binary Plants

The reported production data for the binary plants can be similarly used to assess the typical well flow rate. Figure B-3 shows the producing well count for binary plants and the average flow rate reported. This figure is based on reported data from binary plants at the Steamboat complex, Soda Lake, Stillwater, Empire, Wabuska, Blue Mountain, Salt Wells, Jersey Valley, McGinness Hills, and Tuscarora. Average flow rates have increased with time, as has the number of wells reporting production flow. The increase in the number of wells reporting is indicative of the startup of newer plants.

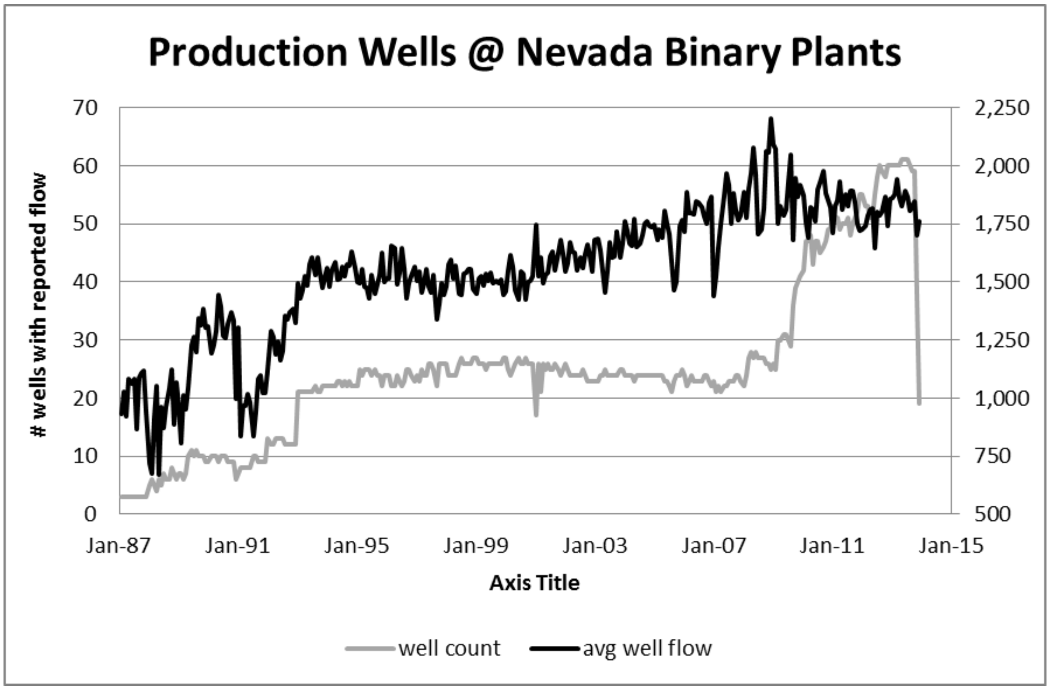


Figure B-3. Number of production wells and the average flow at Nevada binary plants.

Similar to what was done with the flash plants, the distribution of the reported flow rates were examined in consideration of a representative production well flow rate for the binary plants. Figure B-4 below shows those distributions.

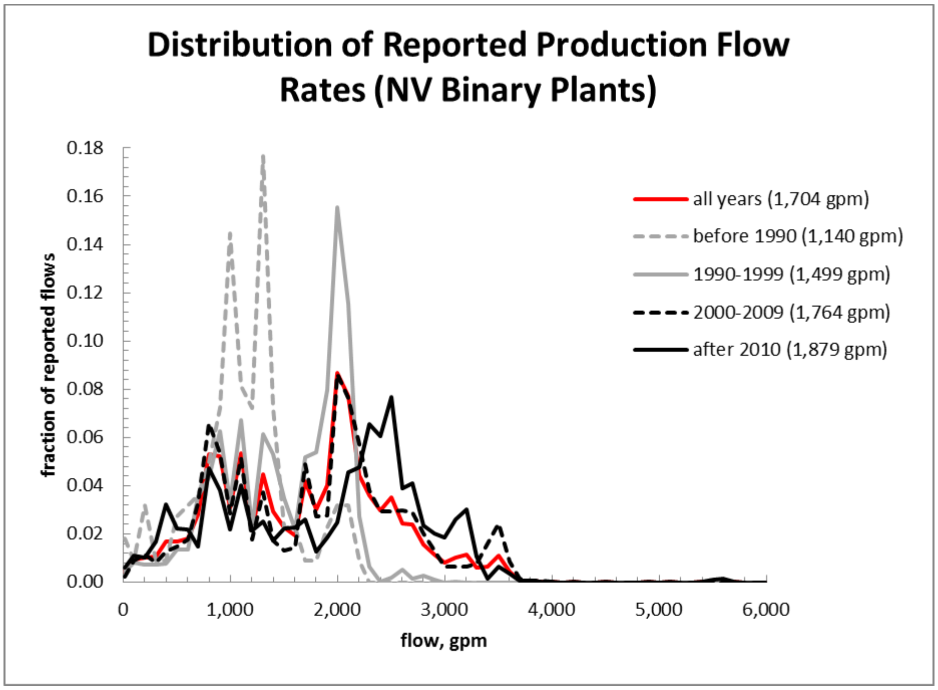


Figure B-4. Distribution of reported flow of Nevada binary plants by decade.

As with the flash plants, there is considerable variation in reported flow rates for wells supplying binary plants. The most frequently reported flow rate increased after 1990 to approximately 2,000 gpm. This flow remained the most frequently reported through 2009. This is likely due to a significant portion of the binary generation capacity having been developed at Steamboat during this period. After 2009, the most frequently reported flow increased again. This likely reflects the new production for binary plants that have started up since 2009.

No specific technology advances have been identified that allowed the flow rates for the binary production wells to increase. These flows could be indicative of the increased use of electric submersibles that allow for increased setting depths and higher flows. They could also be the result of wells being completed with larger casing, or with wells being drilled with less formation damage. While these could certainly have contributed to the higher flows, it is doubtful that these increases can be attributed solely to these factors. If resource temperatures for these new projects are lower (which may generally be the case), the production well flow rates would have had to increase for the project to be economically viable. It is likely that these economic considerations have contributed to the recent increase in the reported flow rates.

The default flow rate used in GETEM for binary plant production wells is 110 kg/s. For a 175°C resource, this corresponds to a volumetric flow rate of ~1,950 gpm. In looking at Figure B-4 above, the most likely flow rate, when considering all years, is ~2,000 gpm, which is higher than the averages for any of the time periods shown. If one considers production that has occurred since the beginning of 2010, the most likely flow is ~2,500 gpm. A flow rate of 2,000 gpm corresponds to a mass flow of ~ 112 kg/s, while a flow rate of 2,500 gpm would correspond to ~140 kg/s (both flows for a 175°C fluid).

Injection Well Flow

GETEM does not utilize a specific injection well flow; rather, it bases the flow rate to the injection well on a ratio of production to injection well flow and the specified or default production well flow rate. The default flow ratio for the wells is 0.75 for hydrothermal resources and 0.5 for EGS.

Figure B-5 summarizes the total number of wells used with Nevada binary plants that had reported injection and production well flow. Since the early 1990's the ratio of the injection to production wells has been between 0.5 and 1.0. With the assumption that all produced flow is injected, this ratio is effectively the same as the GETEM default for the ratio of production to injection well flow. The data from the NV binary plants would suggest that the GETEM default of 0.75 for this flow ratio is representative of binary facilities.

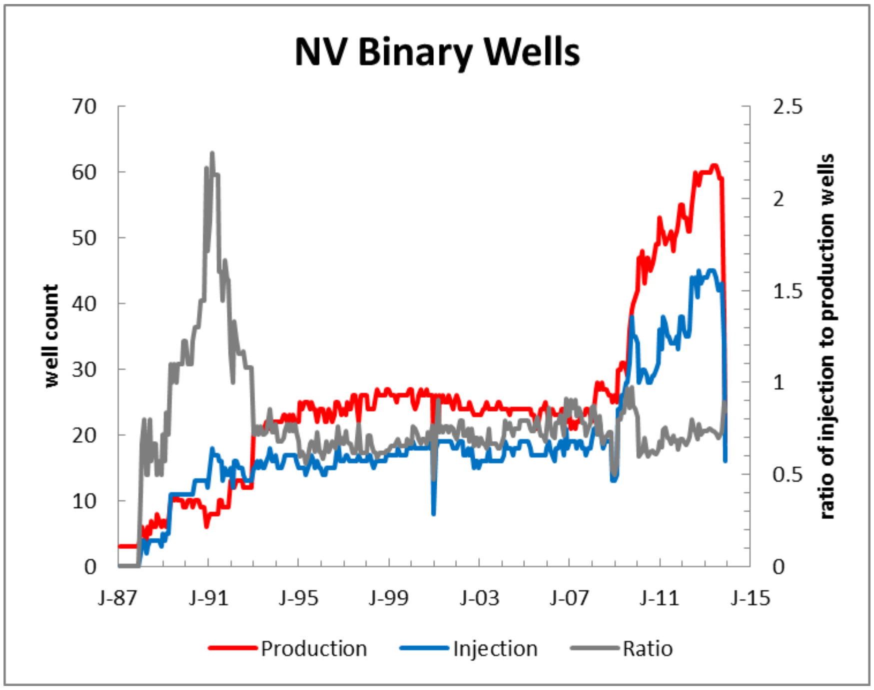


Figure B-5. The total number of Nevada binary wells with ratio of injection to production wells.

The data reported for the Nevada flash plants was used to make a similar comparison of injection and production wells. That comparison is shown in Figure B-6.

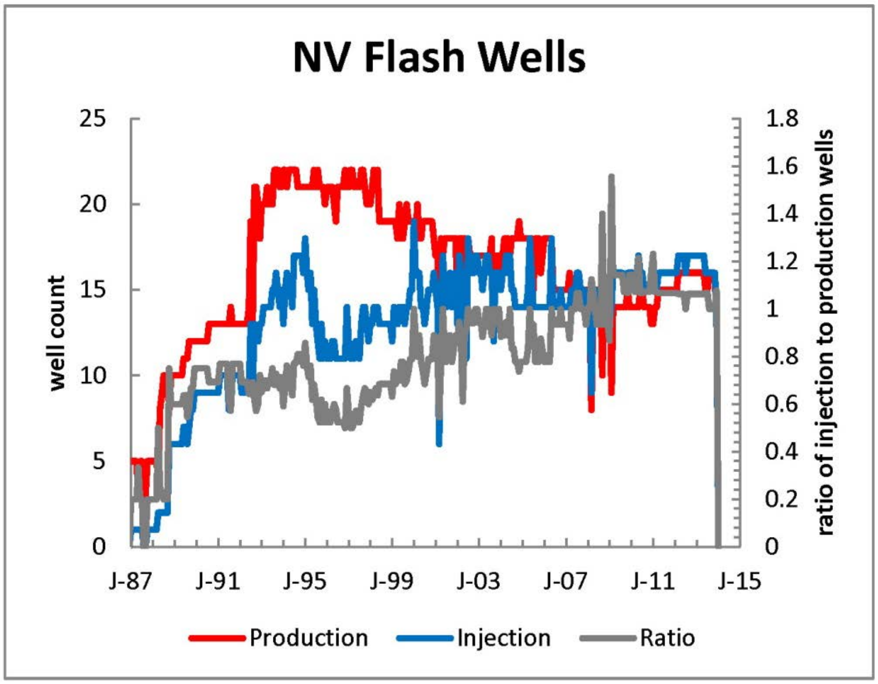


Figure B-6. The total number of Nevada flash wells with ratio of injection to production wells.

The reported data for the flash plants indicates the ratio of injection to production wells has increased from 0.5 to 1. Given that there have not been any new plants coming online, the increase in the number of injection wells is indicative of a change in operation at these facilities with time. One possible explanation is that these plants could be injecting non-geothermal fluids to supplement injection and require more injection wells. In looking at the well counts, the number of injection wells has increased over time. The change in the ratio appears to more likely be the result of using fewer production wells. It is not clear why production well flows may have increased, other than less productive wells may have been taken out of service as the plant “aged.”

GETEM’s depiction of how the geothermal fluid is injected was revised in 2015. The current default for the model is to use “failed” production and injection wells to supplement injection (i.e., these wells are part of the injection system even though they may not take much fluid). Dick Benoit indicated this was done at both Beowawe and Dixie Valley during the early years of operation. This use of failed wells for injection would have increased the ratio shown, and unless these wells completely stop accepting flow, there is no incentive to take them out of service unless they are adversely affecting production (flow or temperature).

Figure B-7 below shows the reported flows for the flash plant. Note the operators report gallons per month—those values were converted to gpm, assuming the well operated continuously throughout the reporting month. The difference between production and injection flow is largely due to the use of condensed steam as makeup for heat rejection systems. A portion could also be due to a difference in the temperatures of the fluids.

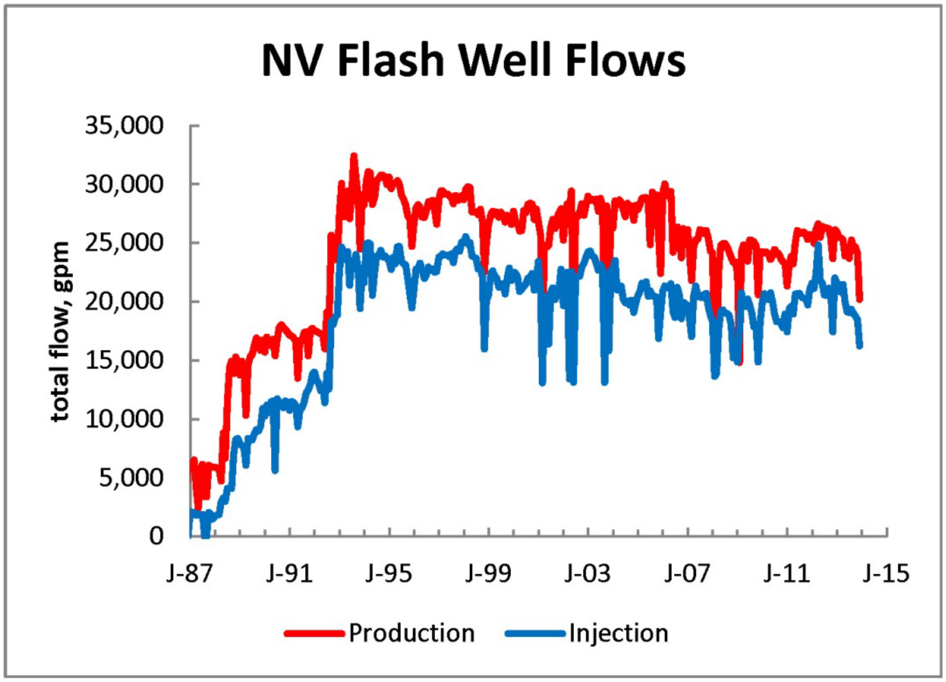


Figure B-7. Reported production and injection flows for Nevada flash wells.

The reported flows have decreased with time (as have the number of production wells). This would suggest:

1. the operator continues to use all available injection capacity, and/or
2. mineral precipitation has occurred in the well bore or formation that limits the ability of the injection wells to accept flow.

Supplemental Use of Failed Wells

When drilling wells, presumably those considered "failures" lack fluid, temperature, and/or permeability. Based upon discussions with industry, the use of "failed" wells to supplement injection appears to have been common, especially with the older plants in Nevada. Though this supplemental usage is likely to vary between projects, it is now the default for GETEM's characterization of hydrothermal resources. In order to estimate the number of injection wells that are required, it is necessary that an assumption be made of the relative permeability of the "failed" wells that supplement injection. A relative flow was established for these supplemental wells using the data reported to the Division of Minerals by the geothermal operators in Nevada. The following assumptions were made:

- When flow is reported for a well, it is assumed that the well took flow continuously throughout the month at a constant rate.
- For a well to be considered used for supplemental injection, it had to have 12 months or more of reported flow, unless the well had been used continuously since it began operation (brought online during the last year of report data—2013).
- Wells having an average flow that was 90% or more of the average flow of all wells were considered "successful" injection wells. Though the 90% value is somewhat arbitrary, the basis for this criteria is that if wells are being used for supplemental injection, they will suppress the average injection well flow for the facility.

$$average\ well\ flow_{facility} = \frac{\sum total\ reported\ monthly\ flows_{field}}{\sum \#\ wells\ reporting\ flow\ each\ month_{\ field}}$$

If a well did not report flow in a month, it was not included in the summation in the denominator. In evaluating whether a well was successful, its average flow was calculated based on those months during which it had reported flow (>0).

$$average\ flow_{well} = \frac{\sum monthly\ flow\ reported_{well}}{\sum months\ reporting\ flow > 0_{well}}$$

If this average flow for a well was >90% of the *average well flow* $_{facility}$, the well was successful. The average flow of the facility's successful well was weighted such to reflect the number of months that each successful well had reported flow.

$$\text{average successful flow}_{\text{facility}} = \frac{\sum(\text{average flow} \times \#\text{months reporting flow})_{\text{successful well}}}{\sum \#\text{months reporting flow}_{\text{successful well}}}$$

The average flow rate for the facility's successful wells was then compared to the average flow of those wells not deemed successful (because they fell below the 90% threshold) to determine a relative flow ratio for the well.

$$\text{flow ratio}_{\text{well}} = \frac{\text{average flow}_{\text{well}}}{\text{average successful flow}_{\text{facility}}}$$

This flow ratio was then used to determine a weight relative flow for the facility.

$$\text{relative flow}_{\text{unsuccessful}} = \frac{\sum(\text{flow ratio}_{\text{well}} \times \#\text{montly reports})_{\text{unsuccessful}}}{\sum(\#\text{montly reports})_{\text{unsuccessful}}}$$

This represents the flow rate of all the unsuccessful wells for the facility relative to those wells considered successful (as defined by above criteria). The following table summarizes the flows for the Nevada binary and flash plants.

Table B-1. Summary of flows for Nevada binary and flash plants.

Facility	total wells used	avg well flow {gpm}	Successful Injection wells	Avg - Suc IW [gpm}	Supplemental wells	Relative Flow	Rel Flow (all wells)
Binary	**94**		**31**		**38**	**0.309**	**0.304**
Steamboat	26	3,991	6	10,030	11	0.205	0.200
Empire	9	967	3	1,322	5	0.231	0.235
Soda Lake	16	1,003	4	1,175	3	0.532	0.504
Stillwater	16	1,559	6	1,837	6	0.488	0.481
Wabuska	NA	NA	NA	NA	NA	NA	NA
Blue Mt	10	1,562	4	1,942	4	0.435	0.416
Salt Wells	4	2,802	2	4,279	2	0.209	0.209
Jersey Valley	5	655	2	955	3	0.331	0.331
Tuscarora	5	1,616	2	2,054	3	0.646	0.646
McGuinness Hills	3	2,895	2	3,423	1	0.554	0.554
Flash	**31**		**9**		**16**	**0.276**	**0.276**
Dixie Valley	13	960	3	2,328	9	0.209	0.209
Beowawe	2	2,776	1	3,364	1	0.526	0.526
Desert Peak	3	1,641	1	1,722	0	NA	0.074
Brady	13	2,146	4	2,565	6	0.580	0.562
All geothermal	**125**		**40**		**54**	**0.292**	**0.290**

There is considerable variation in the average injection flow both for all wells and for those wells that are considered "successful." At some facilities (for example, the Steamboat Complex), the injection flow rate of some of the wells used for supplemental injection wells exceed the flow rate of wells that are considered successful at other facilities. This is an artifact of both the criteria used to define success and the very high flow rates of "successful" wells at these facilities.

The data for Dixie Valley suggest that a number of wells provide supplemental injection capacity. At this plant, three wells have been taking over half of the injected flow—since 2001, they have been taking up to 70% of the injection. The other wells that have been used for injection have a relative flow of ~21%. (On average, they each accept ~21% of the 2,328 gpm for the “successful” wells). Table B-1 shows the relative flow both for wells that meet the 12-month criteria used to define supplemental wells, as well as the relative flow for all wells that have had reported flow. For those facilities that have been operating for a number of years, there is minimal difference between the two values.

The values found for the relative flow indicate considerable variation between facilities. This is indicative of the differences between reservoirs. The averages for all the facilities is similar for both flash and binary plants—about 0.3. The default in GETEM for the relative productivity of failed wells used to supplement injection is 0.3.

Productivity/Injectivity Index

GETEM assumes that the productivity index (PI) and injectivity index (II) are equivalent. A value of 2,500 lb/hr per psi used when either a binary or flash plant is used. This value is taken from the EPRI’s study (EPRI 1996). The PI and II will vary both from resource to resource and from well to well at a given resource. It is assumed that the PI and II are equivalent. There is some basis for this assumption, as shown in Figure B-8, which was taken from Garg and Combs’ paper (Garg 2000). For reference, the GETEM default is equivalent to ~4.6 kg/s per bar; this figure would suggest this value is not improbable.

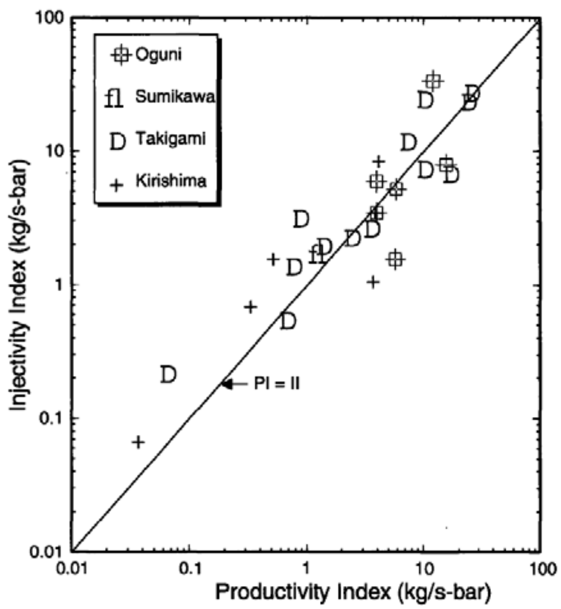


Figure 1. Injectivity Index (II) versus Productivity Index (PI) for Oguni, Sumikawa, Takigami, and Kirishima Boreholes with Liquid Feedzones.

Figure B-8. Injectivity index and productivity index for Oguni, Sumikawa, Takigami, and Kirishima boreholes with liquid feed zones (Garg 2000).

Figure B-9 below is taken from the 2014 GRC presentation (Allis and Moore 2014). It is modified from data originally found in a paper from the 2013 Stanford workshop (Grant 2013). This figure shows the injectivity and productivity measured during testing of a number of wells from hydrothermal resource developments in New Zealand. The Mod PI/II (orange line) represents the GETEM default.

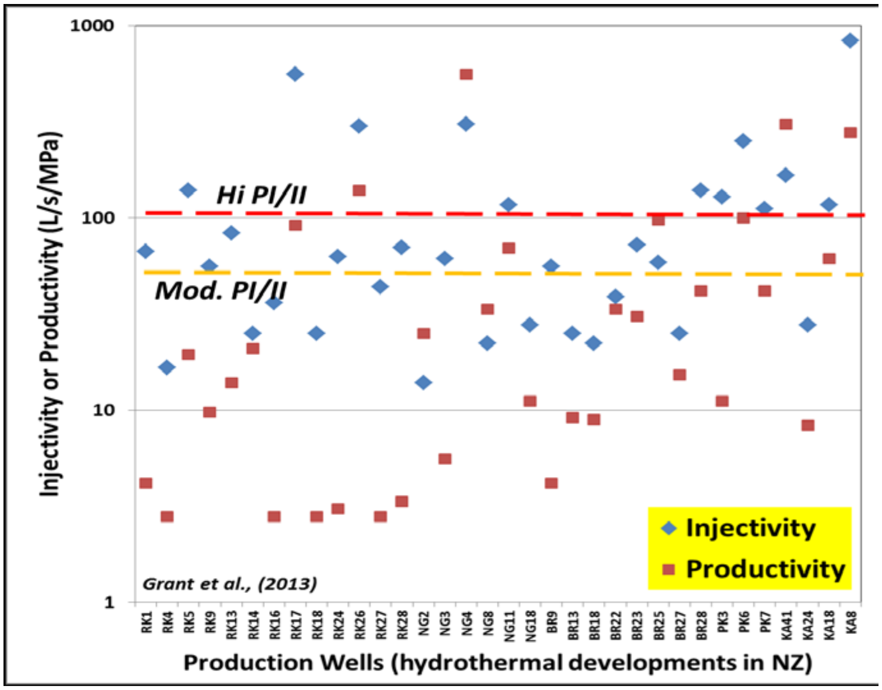


Figure B-9. Injectivity and productivity indices observed during testing of wells in New Zealand.

The values in this figure would suggest that the PI and II are not necessarily equivalent; they also suggest that the magnitudes of the PI and II defaults in GETEM are not unreasonable.

An attempt was made to estimate the injectivity index from the data provided by the Nevada operators. The values had significant variation, likely reflecting the quality of the data that was used. Examples of values estimated for the II for different facilities are shown in Table B-2 below. These are averages over the reporting period through 2009. The GETETM default for the II in Imperial units is 5.6 gpm per psi, which is with the range of values determined for these facilities.

Table B-2. Injectivity index values estimated for facilities listed.

Facility	Injectivity Index (gpm per psi)
Soda Lake	2.6 to 77
Blue Mt	4 to 7.2
Salt Wells	4.9 to 575
Stillwater	2.9 to 6.7
Steamboat II &III	28 to 220

B2: RESERVOIR PRODUCTIVITY DECLINE:

Nearly all geothermal resources experience some decline in productivity over time. This decline could occur as reduced flow, temperature, and/or pressure of the produced geothermal fluid. Given that geothermal reservoirs have a finite size, a decline in productivity is not surprising. Conversion systems extract energy from the produced fluids and return it to the reservoir as a cooler fluid. The geothermal flow rates required to produce electrical power are relatively high. A 30 MW binary plant using a 175°C resource will produce just over 4 billion barrels of fluid over a 30-year life; this is over half the ~7 billion barrels of petroleum products consumed by the U.S. in 2015 (EIA). The 4 billion barrels used by the binary plant are equivalent to ~0.66 km^3 of fluid, which would suggest that the produced fluid is cycled multiple times through the reservoir, mining the heat in place. The flash steam conversion system typically utilizes the steam condensate for makeup of the plant's evaporative cooling system. As a consequence, less water is injected than is produced, potentially depleting the amount of fluid in the reservoir.

The liquid-dominated resources are more common and are the basis of GETEM's depiction of a geothermal resource. This depiction assumes that the geothermal fluid entering the production zone in the well is a liquid, and remains a liquid at this point throughout the operating life of the well. GETEM characterizes the pressure decline that occurs using a productivity index (a model input) that is based upon the hydraulic pressure drawdown in the production well having reached a quasi-steady state value with time. With binary plants, the downhole production pumps offset the decline in reservoir pressure. Flash plants typically do not use production pumps, and the pressure drawdown impacts where flashing occurs in the production well.

The premise for GETEM's estimates of how declining reservoir productivity impacts generation is based on the well flow rate remains constant with time and the pressure drawdown has reached its quasi steady state value. As such, neither flow nor pressure is included in GETEM's characterization of declining resource productivity. This decrease in resource productivity is characterized as a declining resource temperature that is based on the following relationship:

$$T_n = T_{initial}(1 - annual\ decline\ rate)^n,$$

where T is temperature, n is a point in time during the facility operation, and the annual decline rate % change in the temperature occurs annually (a GETEM input).

This relationship is used to determine the temperature of the produced fluid throughout the life of the project with GETEM's assumption that all production wells are identical—that they have the same productivity index, and produce the same temperature and flow rate.

At a given point in time, the model uses this temperature and an ambient temperature to estimate the ideal work that could be accomplished by a power cycle. A second law efficiency is applied to this ideal work to calculate the actual work done, which is used as a net capacity factor to determine the plant's net output at that point in time.

The declining resource temperature adversely impacts plant output and the power sales over the life of the project. This is illustrated in Figure B-10, which is GETEM's estimate of the annual power generation for different rates of temperature decline.

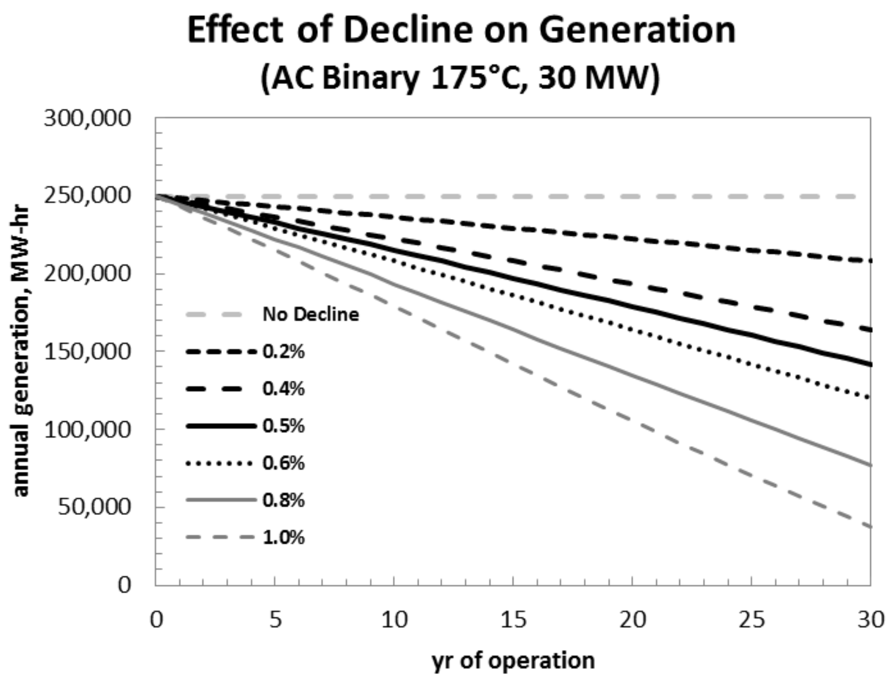


Figure B-100. Effect of declining resource temperature on annual generation for sale.

As the resource productivity decreases, it is common for geothermal operators to increase the production flow to offset any significant impact on power generation. They will accomplish this by drilling additional wells and/or installing larger production pumps are greater depths. GETEM does not attempt to account for changes in production flow, as it is a site-specific activity and difficult to characterize for a "representative" plant. Instead, GETEM accounts for the impact of excessive temperature decline by replacing the entire well field once the decline reaches a maximum threshold value. In the model, this replacement occurs unless the project is in the last 5 years of its indicated life or insufficient resource potential was discovered to allow for replacement of the field (this resource potential is a model input). GETEM allows for multiple replacements as long as these two criteria are satisfied.

The default for the maximum temperature decline allowed is based on the end-of-project temperatures given in EPRI's study (EPRI 1996). These values approximate a decline of ~10% in the Carnot efficiency as depicted here:

$$T_{replacement} = \frac{T_o}{\left[0.9 \times \left(\frac{T_o}{T_{initial}}\right) + 0.1\right]}$$

In this equation, all temperatures are absolute (either °K or °R), and T_o is the temperature to which heat is rejected (ambient). The current model default assumes that sufficient potential was discovered to allow for one well field replacement. In the scenario depicted in the above figure, GETEM would have replaced the well field once each for both the 0.8% and 1% decline rates.

With replacement, it is assumed that the produced fluid returns to the initial temperature, and that the power production returns to the original (design) output. The costs for the wells, pumps, and other components are included in the replacement costs and are discounted to determine their present value at startup (as are the revenues from the power sales) when determining the LCOE.

Though GETEM handles the effect of resource decline similarly for both flash steam and air-cooled binary plants, both have different default values for the temperature decline rate.

Binary Plants

Quantifying the temperature decline for binary plants was accomplished using the production reports submitted to the Nevada Division of Minerals by the geothermal operators. Hanson (2014) has done this assessment for the binary facilities in Nevada. In this evaluation, an energy balance was performed for each facility using the reported data to determine a plant inlet temperature on a monthly basis. As indicated in Figure B-11, all plants experienced some level of temperature decline over time. In some instances, there was initially a severe decrease, with subsequent recovery of the temperature. This is most likely due to the initial injection of fluid in close proximity to the production wells; when injection was relocated, the temperature recovered. In one instance, new production wells were drilled to greater depth to access a hotter reservoir. Once operations became stable at these facilities, the slopes of the temperatures over time are very similar. These slopes are indicative of the relative change in temperature over time that is needed to determine the decline rate used in GETEM.

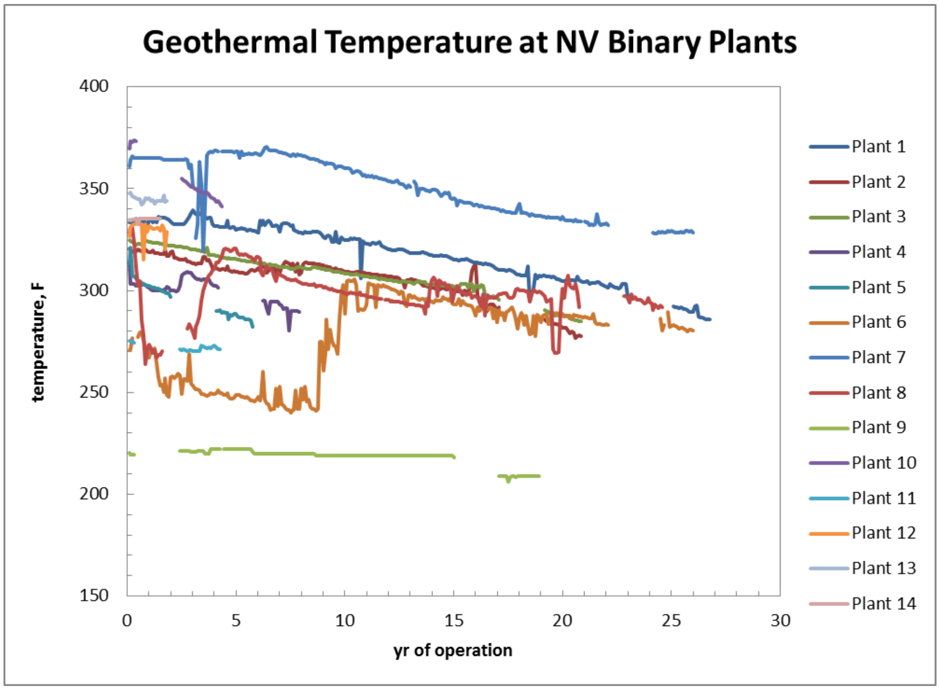


Figure B-11. Decline of geothermal temperature at Nevada binary plants over a 30-year period.

Figure B-12 below illustrates how the reported temperatures for individual wells changed over time, with the reported temperature plotted relative to the initial production temperature (within an average of the first 4 months of operation) for each well.

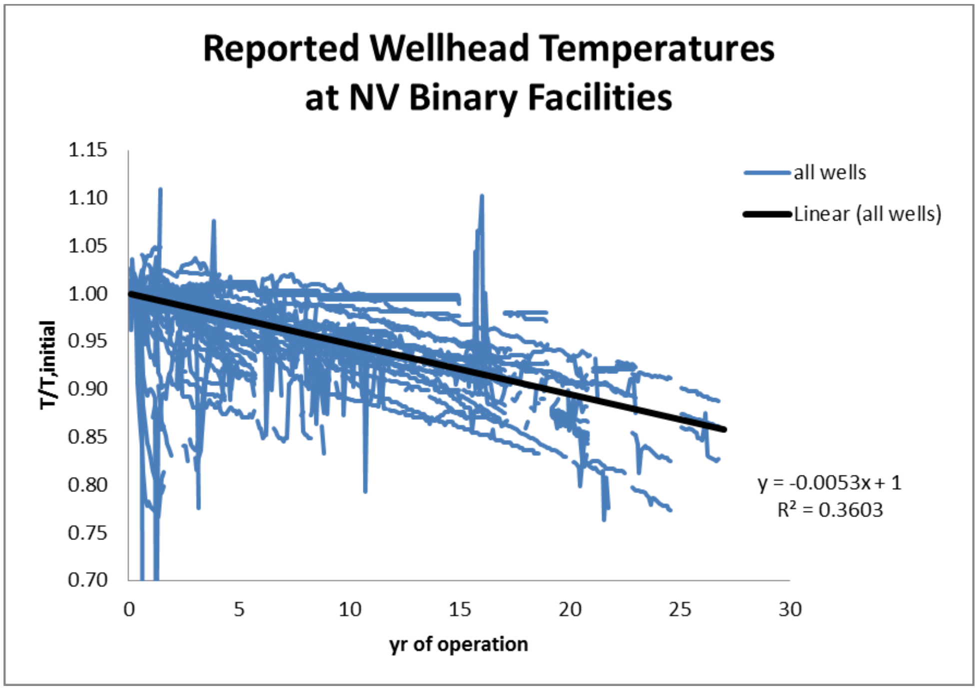


Figure B-12. Reported wellhead temperature decline over time at Nevada binary facilities.

Except for a few wells that have only been in operation for a short time, these wells experienced a decline in temperature. Some experienced a rapid decline; if this decline was not mitigated by moving injection, these wells were typically taken out of service and not used. For some months, the reported temperatures were abnormally high or low. The higher values are likely errors in the reporting. The low values are either errors or reflect intermittent production from the well. Shown in Figure B-13 is a linear fit of all the data with the intercept at time 0 forced to be equal to 1. The slope of this line reflects the annual decline of the temperature for all wells relative to their initial operation. The decline of individual wells shown in this figure is of interest because if the rates differed significantly from that determined for the fluid entering the plants, it would suggest that there is significant post-startup replacement of wells.

In Figure B-13, the production temperatures determined for the Steamboat Complex facilities are shown as a function of time and total production flow. The solid black line in the figure on the left is a linear curve fit of data for all of the facilities. The slope of this line approximates the decline rate needed in GETEM. The figure on the right shows the temperature that is determined from the total enthalpy and total flow of the fluid entering all the producing binary facilities. This "weighted" temperature is plotted as a function of the cumulative flow of all facilities, beginning with the SBI plant. The colored symbols depict when the other facilities began operation. Steamboat Hills is a flash plant, and though its reported temperatures were not used in determining the temperatures shown, its reported flow was included in the running total flow produced. The value in parentheses after each plant's name shown is the year it began reporting flow to the NV DoM.

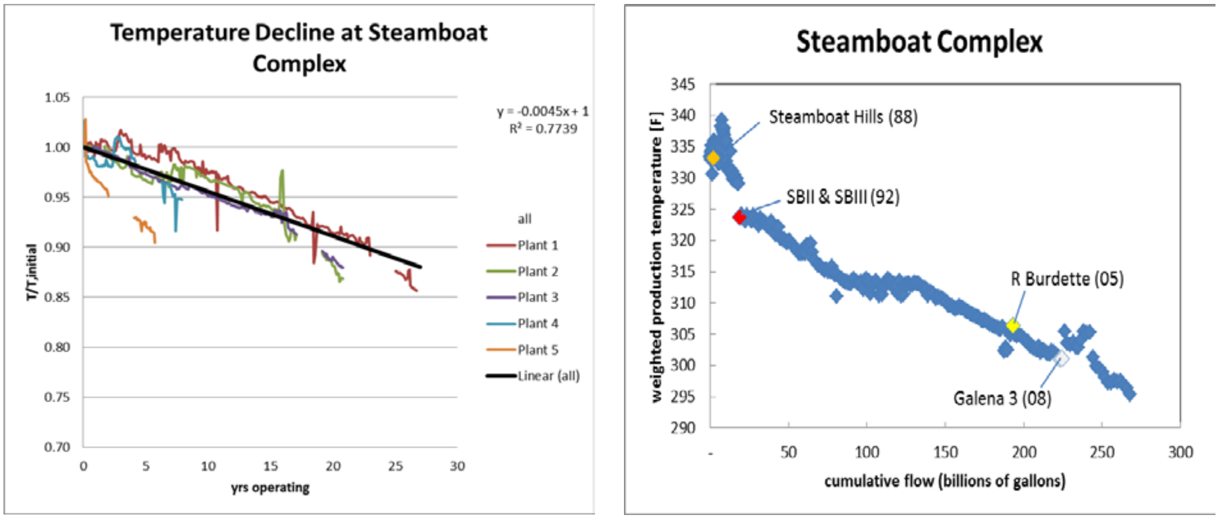


Figure B-133. Temperature decline of the Steamboat Complex over 30 years (left) and as a function of total cumulative production flow (right).

Figure B-14 shows the change in production temperature over time for the remaining Nevada binary plants, exclusive of those at the Steamboat Complex. Below are the temperatures for the “older” plants, which began operation prior to 2009.

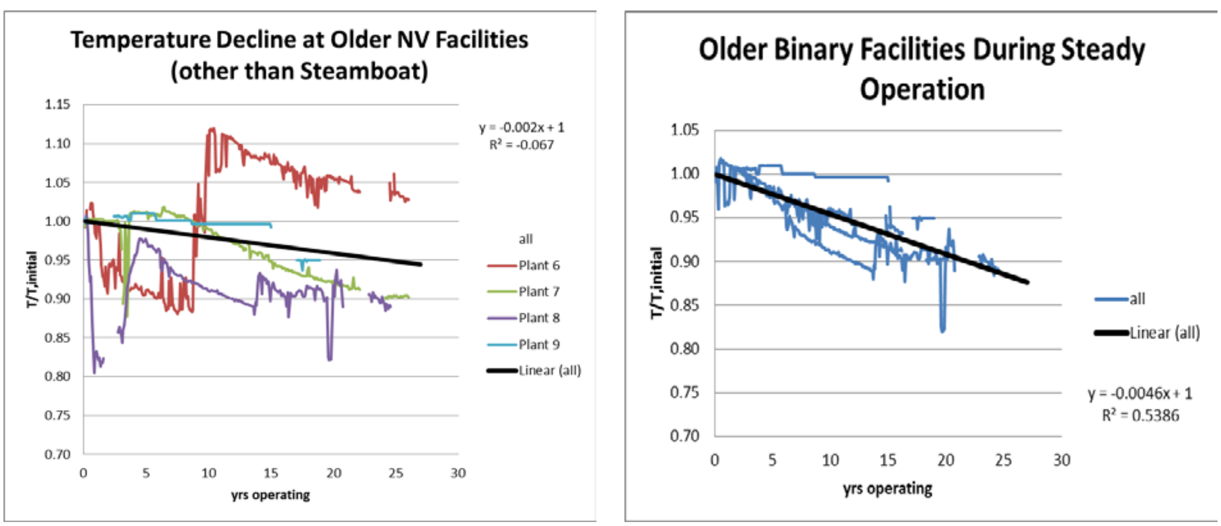


Figure B-14. Temperature decline of Nevada binary plants (exclusive of those at the Steamboat Complex) over 30 years.

There is significant deviation in the individual decline rates for the older plants (left figure). This is due largely to significant changes that occurred at two of the facilities: Empire/San Emideo (Plant 6) and Stillwater (Plant 8). At Empire, production was switched to a deeper, hotter resource 8-9 years after startup. At Stillwater, the proximity of the injection at startup produced rapid initial temperature decline; the temperature recovered after ~5 years once the injection wells were relocated. In the figure on the right, those early years of operation at Empire and the period of operation at Stillwater impacted by injection are excluded. All plants were combined into a single data set with time starting for both

Stillwater and Empire once their operation had stabilized. With this adjustment to this data, the overall decline for these older facilities is similar to that determined for the Steamboat Complex.

Figure B-15 below shows the changes in production temperature for the newer binary facilities in Nevada. The gap in the temperatures represents a 2-year period during which they were not available in information provided by the NV DoM.

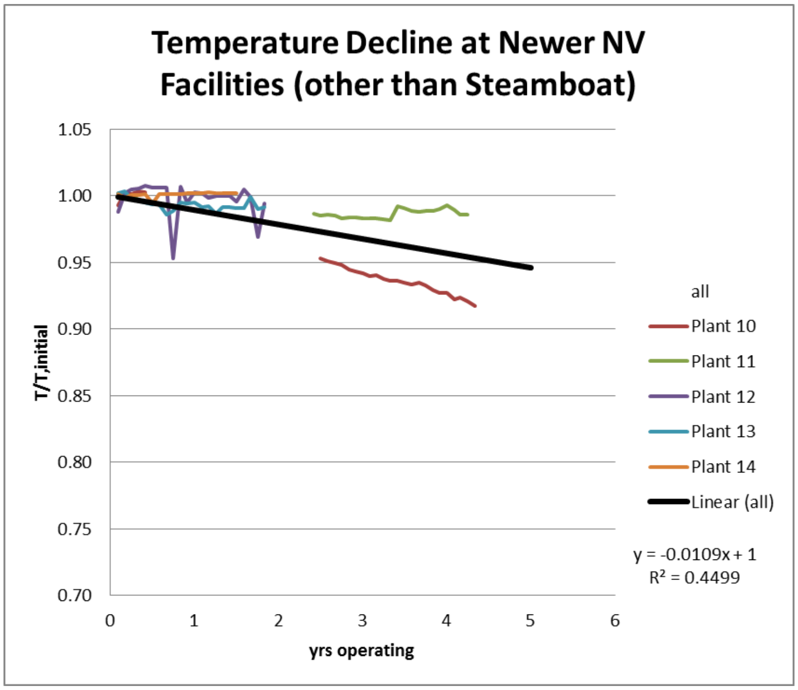


Figure B-15 Temperature decline for newer binary facilities in Nevada.

The decline rate found for the newer facilities was significantly higher than that for the older facilities. This is largely because of the temperature decline at Blue Mt. (Plant 10). With this facility removed from the data set, the slope of the linear fit is −0.004, which is similar to the older binary plants.

A fit of all the Nevada binary plant data, yields a slope of ~−0.003. This value is low primarily because of the impact of the Empire data. If the Empire data is excluded, the slope increases to −0.0042.

This assessment indicates that the slope of the relative decline is between −0.004 and −0.0046. Using these slopes, the annual temperature decline rate can be determined; that rate would vary from 0.42% to 0.48%. The relative change in the temperatures entering the plant are slightly lower than the overall relative change in the temperatures from all production wells. This would suggest that some re-drilling has occurred, with new wells being used to supplement initial production. If one were to use the slope of the decline for the production wells, the annual decline rate would be 0.56%. This rate does include wells that were taken out of service because they experienced a rapid initial decline in temperature. It is believed that the decline rates based on the temperature of the fluid entering the plants is more representative of the reservoirs.

Flash Plants

Operators of the Nevada flash plants also submit the production well temperatures and flow rates to the Division of Minerals; however, the reported temperatures cannot be used (as they were for the binary plants) to determine the decline in resource temperature. Because the geothermal fluid is typically allowed to flash in the wells, the reported wellhead temperatures are those of the two-phase flow and are not indicative of the resource temperatures. It would be possible to use the reported temperatures to determine changes in the resource temperature if the relative amounts of steam and liquid were reported. These values are not reported; the operator reports only a well flow rate (assumed to be total flow). Because the reported well conditions cannot be directly related to the resource temperature, the power production for the plant was used to estimate the changes in the resource temperature over time.

Dick Benoit's paper at the GRC (2014) reviews the performance of flash plants in Nevada. To show how performance has changed with time, Benoit used the metric of how much geothermal flow is required to produce a MW of power. An increase in this metric would be indicative of a decrease in the reservoir temperature. The paper indicates that at Beowawe, initially the temperature decreased by 7–8°F annually, with a decrease from 410 to 348°F in the first 10 years. Since that time, the performance metric has not changed significantly, indicating there has been minimal subsequent temperature decline. The Bradys resource temperature is stated to have decreased by 36°F in the first year and ~100°F since the start of operations. Benoit attributes this to a large plant operating on a small resource. In contrast, the performance metric for the facility at Dixie Valley has been relatively constant, with some increase since 1996. Benoit's 2015 GRC paper indicates there has been "modest" cooling of the Dixie Valley resource; in a phone call earlier this year, Benoit indicated that the temperature decline there has been 1° to 2°F annually.

In the 2014 GRC paper, Benoit cautions about the use of the data reported to the NV DoM (Benoit 2014). The methods by which the well flow rate differs between facilities and likely have changed at a given facility over time. In addition, ownership of the facilities has changed, and the diligence in obtaining and reporting the data has likely changed as well. Regardless, an attempt was made to use the reported flow and power production data to identify the rates at which the temperature has changed at two of the facilities—Dixie Valley and Beowawe.

Figure B-16 below is taken from Benoit's GRC paper (2014). Three points in time (orange lines) were used to estimate the changes in resource temperature over those intervals. The first data point is after 1 year of operation. At this point in time, the temperature was assumed to be 400°F (reflecting the significant decline indicated for the first year of operation). With an assumed wet bulb temperature of 50°F, the plant second law efficiency was determined using the value of the performance metric at that time.

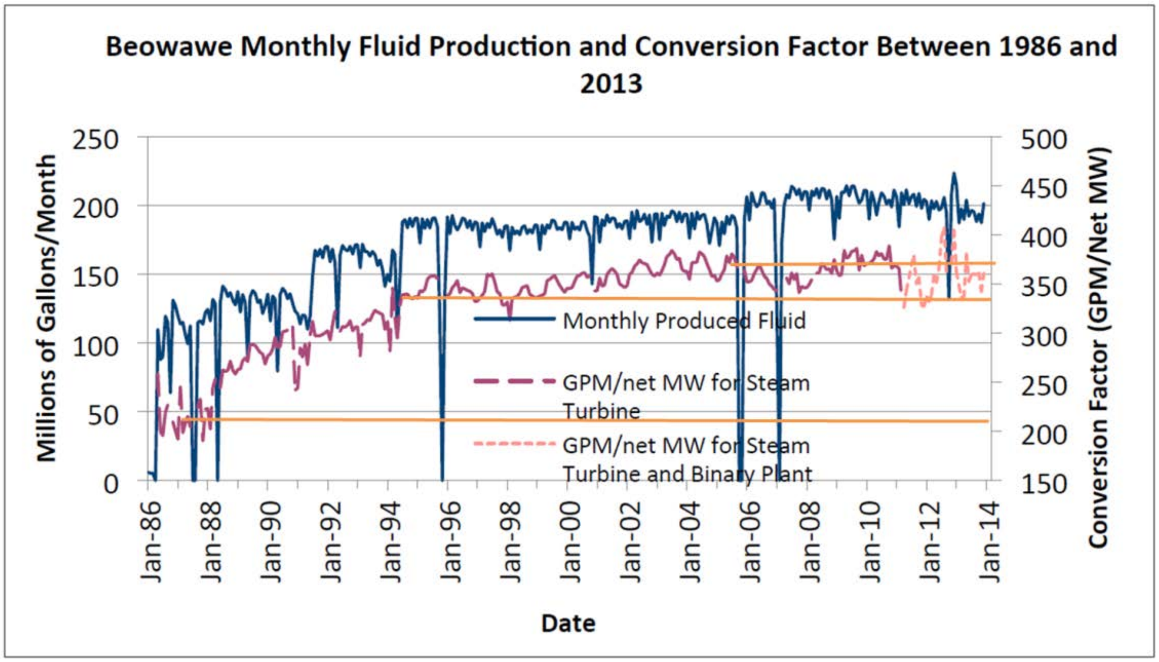


Figure B-146. Monthly fluid production and conversion factor between 1986 and 2013 at Beowawe.

Assuming this efficiency remains constant, and using the 50°F wet bulb temperature, a resource temperature can be determined that produces the indicated performance metric in 1994 and again in 2005. With this approach, the resource temperature is estimated to be 320°F in 1994 and 306°F in 2005. Though the magnitude of these values change if different second law efficiency or wet bulb temperature are used, the magnitude of the estimated decline between 1994 and 2005 would not change that much. This approach indicates that over this 11-year period, the temperature decreased by ~14°F.

A similar approach was used for Dixie Valley based on Figure B-17 below (from Benoit's 2014 paper). The time period of interest was from 1996 to 2012 when a binary bottoming unit began operating at the facility. To produce the change in the performance metric, the temperature decreased by ~30°F over this 16-year period. This value is consistent with anecdotal value that Benoit provided.

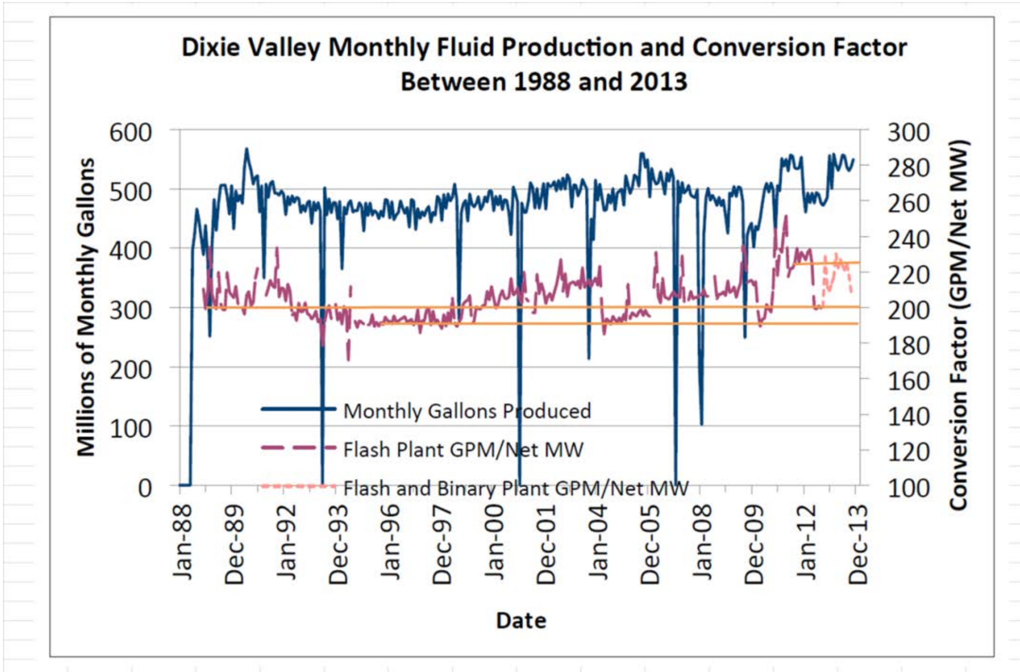


Figure B-17. Monthly fluid production and conversion factor between 1988 and 2013 at Dixie Valley.

There are issues with this approach, one of which is that the plant conversion efficiency does not remain constant. Invariably, when either the brine flow or temperature deviates from the design value, the second law efficiency changes (likely decreases). A decreased efficiency would increase the temperatures needed to produce indicated levels of performance.

To account for the impact of the efficiency, the design information for each plant was taken from Benoit's 2014 GRC paper (geothermal temperature and flow rate, as well as net power). Using the assumed wet bulb temperature of 50°F, a model of a "pseudo" dual-flash plant was developed and used to estimate the impact of varying geothermal temperatures and flow rates on the plant output. These results were used to develop a correlation for each plant that estimated the impact of changes to both flow and temperature on the second law conversion efficiency. The correlations were then applied to the monthly data reported to the NV DoM for each plant. To account for changing ambient conditions, an average monthly wet bulb temperature for Winnemucca, Nevada was applied (NOAA). This ambient data set was used for both the Beowawe and Dixie Valley facilities. With the geothermal flow rate and the wet bulb temperature, the resource temperature needed to produce the reported power output to the NV DoM could be determined.

Figure B-18 has the temperatures determined for Dixie Valley. The initial resource temperature was ~480°F (Benoit, 2015).

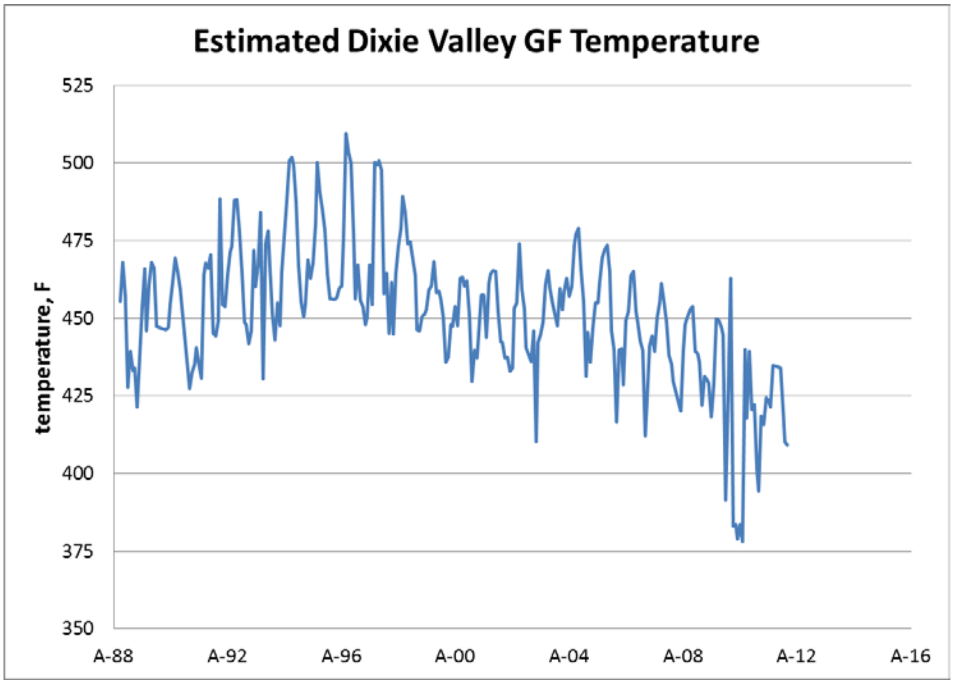


Figure B-158. Estimated geothermal fluid temperature for Dixie Valley based on reported power generation.

A geothermal resource temperature does not vary as indicated in this figure. One reason for this fluctuation is that operators of plants using evaporative cooling systems typically curtail operation of the heat rejection system by reducing air flow during colder periods in order to prevent damage to the cooling tower from ice formation. Those months with the potential for curtailment were taken out of the estimates by considering only those months when the wet bulb temperature exceeded 40°F. Figure B-19 below shows the remaining temperatures.

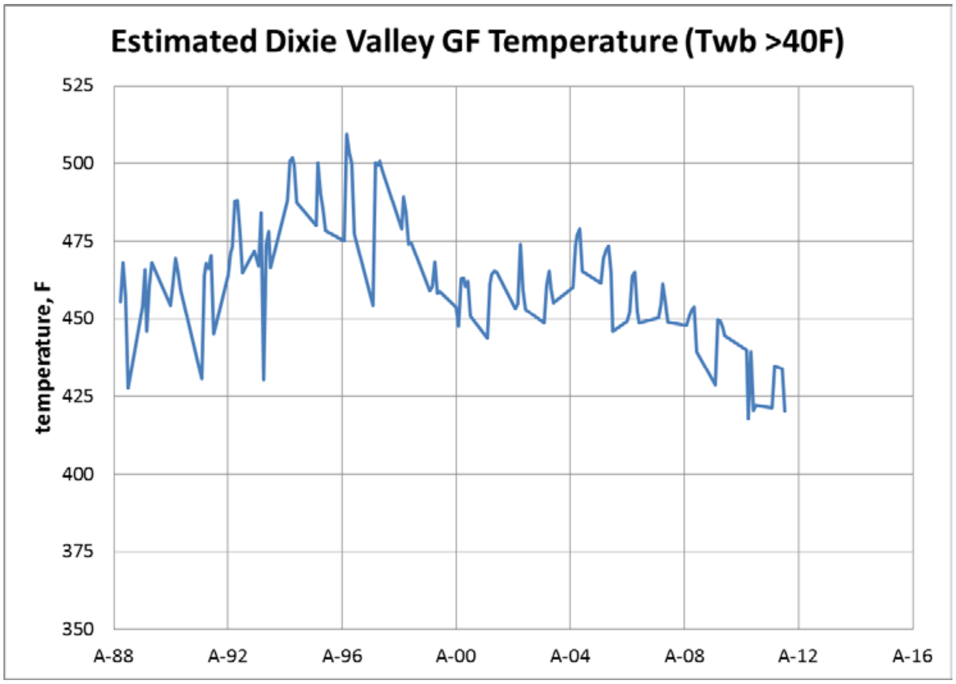


Figure B-19. Estimated geothermal fluid temperature for Dixie Valley based on reported power generation when wet bulb temperature exceeded 40°F.

The absolute magnitude of the estimated temperatures is not of importance other than they should approach the value expected at the beginning of operation. What is of interest is the change that occurs in the estimates over time. The estimates shown indicate that the temperature has declined beginning in about 1996. Benoit’s GRC papers (2014 & 2015) indicate that from startup through 1997, production and injection capacity were changing, with new wells being brought into service; this likely contributes to the apparent increase in temperature occurring after operation began in 1988. The estimates suggest there was an apparent slight temperature recovery in 2004, after which it again declined. This recovery is likely the effect of a modification to the turbine to lower operating pressures and improve its efficiency (Benoit 2015).

Using this data, and considering the period from 1996 through 2010, the temperature decreased ~40°F which is more than the decrease that was estimated using the plots in Benoit’s paper (2015). Data was not considered for 2011 because, during that year, the reported flow rate was ~10–13% higher than the design value that was used. While the approach used to estimate the temperatures included the effect of varying flow, excluding that year was believed to improve the estimate of the decline rate. Excluding all calculated temperatures above 500°F, an annual decline rate of 0.58% was determined for this period (including the higher temperature estimates, increased the decline rate to ~0.64%).

The similar approach was used to estimate the change in the geothermal fluid temperature over time at Beowawe. The estimated temperatures are shown in Figure B-20 below. The temperature of this resource was ~410°−420°F at startup.

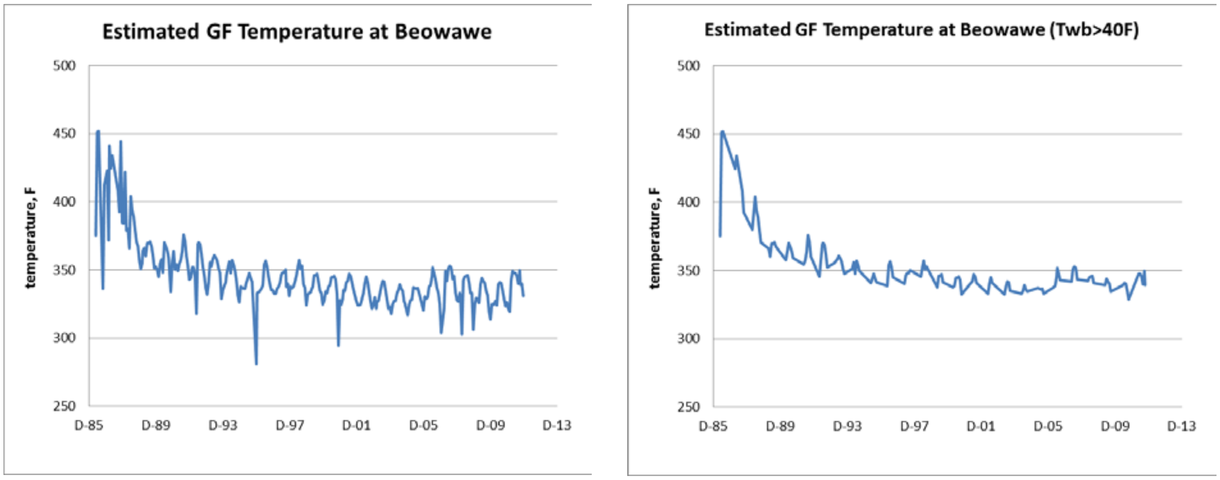


Figure B-20. Estimated geothermal fluid temperature at Beowawe based on reported power generation (left) and the same excluding web bulb temperatures of less than 40°F (right).

Considering the period from 1989 through 2011, the decline rate is ~0.31%. If one considers the entire period from startup through 2011 (and excluding estimates >425°F), the decline rate is 0.45%.

Table B-3 below summarizes the decline rates that were found for these two plants.

Table B-3. Decline rates for Dixie Valley and Beowawe.

Plant	Stable Operation	Entire Life
Dixie Valley	0.6%	0.2%
Dixie Valley (Benoit paper)	0.4%	—
Beowawe	0.3%	0.5%
Beowawe (Benoit paper)	0.4%	—

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